tamarack valley ENERGY ltd.

Annual Information Form

For the Year Ended December 31, 2017

March 8, 2018

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The information in this Annual Information Form is given as of December 31, 2017 unless otherwise indicated.

TAMARACK VALLEY ENERGY LTD.

BACKGROUND

Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is an intermediate, high-growth oil and natural gas company whose rate-of-return focused growth strategy targets the drilling and acquisition of repeatable and predictable long-life resource plays in the Western Canadian Sedimentary Basin. Through accretive acquisitions since inception, Tamarack has successfully assembled an attractive asset portfolio concentrated within high-quality plays in Alberta and Saskatchewan, including Cardium and Viking light oil. The Company has an extensive low-risk drilling inventory which offers paybacks of less than 1.5 years and can achieve sustainable growth under low commodity price scenarios while maintaining a strong balance sheet.

The Company is based in Calgary, Alberta and was incorporated under the ABCA on March 6, 2002 as a "capital pool company" (as defined in the TSX-V Corporate Finance Manual (the "**Manual**")), and possessed no assets other than an experienced senior management team. On April 23, 2002, the Company amended its articles to remove share transfer restrictions and to increase the minimum number of directors. In November 2002, the Company acquired all of the issued and outstanding shares of Dunhaven Energy Inc. ("**Dunhaven**") by way of a take-over bid for consideration of $670,000. The acquisition of Dunhaven constituted the Company's "qualifying transaction" (as defined in the Manual).

On June 17, 2010, the Company completed a Restructuring Transaction, which included the amalgamation of PrivateCo with a subsidiary of the Company, the reconstitution of the Board of Directors, the appointment of a new management team led by Brian Schmidt, and a change of name of the Company from "Tango Energy Inc." to "Tamarack Valley Energy Ltd."

The Company seeks to provide growth for its shareholders by identifying, securing and developing high-quality assets within the Western Canadian Sedimentary Basin and by executing a technically disciplined, full-cycle approach to oil and natural gas exploration and development, combined with continued adoption of new technologies to improve efficiencies.

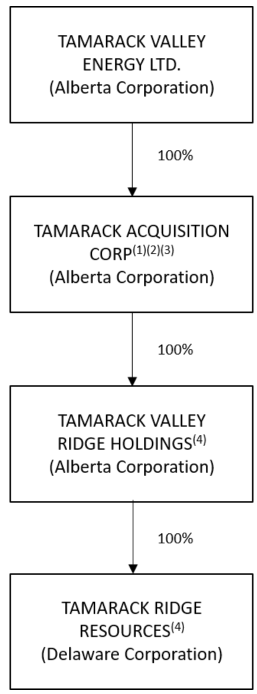
Tamarack is a "reporting issuer" or the equivalent in each of the Provinces of Canada. The Common Shares have traded on the TSX under the symbol "TVE" since August 24, 2015. Previously, the Common Shares were trading on the TSX-V.

The Company's head office is located at Suite 600, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8. The registered office of the Company is located at Suite 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

See "*Selected Abbreviations*" and "*Definitions*" for abbreviations and definitions used in this AIF.

Inter-corporate Relationships

The following diagram presents the name and jurisdiction of incorporation of Tamarack's material subsidiaries as at December 31, 2017**(4)**. The below diagram does not include all of the subsidiaries of Tamarack.



Notes:

(1) On January 1, 2013, Echoex amalgamated with Tamarack Acquisition Corp. ("**TAC**") as part of an internal re-organization of Tamarack with the resulting amalgamated corporation assuming the name "Tamarack Acquisition Corp.".

(2) On October 9, 2013, Sure Energy was amalgamated with Alberta 1767001 with the resulting amalgamated corporation, Sure Amalco assuming the name "Sure Energy Inc.". Subsequently, on October 9, 2013, the corporation resulting from the amalgamation of Sure Energy and Alberta 1767001 was amalgamated with TAC with the resulting amalgamated corporation assuming the name "Tamarack Acquisition Corp.".

(3) On December 31, 2015, the Company's subsidiaries Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp., each partners of Tamarack Valley Energy Partnership, dissolved such partnership. On January 1, 2016, Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp. completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp.".

(4) As of the date hereof, no assets are held within Tamarack Ridge Resources or Tamarack Valley Ridge Holdings.

(5) As of the date hereof, the only material subsidiary of Tamarack is Tamarack Acquisition Corp. On January 11, 2017, Tamarack Acquisition Corp. and Spur Resources Ltd. (a corporation amalgamated under the ABCA in connection with the Viking Acquisition) completed a horizontal amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp."

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Since the Restructuring Transaction, Tamarack has focused on acquiring and developing an attractive land base within its core Cardium and Viking light oil plays. The Company has continued to successfully execute its business strategy to build a sustainable, predictable, low-cost and reliable growth company while maintaining a strong financial position. The following is a summary of the key developments occurring in Tamarack's business over the past three years.

Recent Developments

On March 6, 2018, the Company announced its 2017 year-end operating and financial results and an operations update, along with details from the reserves report prepared in accordance with NI 51-101 by GLJ Petroleum Consultants Ltd. ("**GLJ**") with an effective date of December 31, 2017.

Tamarack's 2017 production averaged 20,136 boe/d (60% oil and liquids), generating funds from operations of $158.4 million ($0.70 per share basic and diluted) and an operating netback of $24.22/boe. On December 31, 2017, net debt stood at $173.2 million. During 2017, the Company drilled a total of 133 (126.4 net) producing wells and 1 (1.0 net) injection well. The 133 producing wells included 104 (99.0 net) Viking wells, 16 (15.3 net) Cardium wells, five (5.0 net) heavy oil wells and three (3.0 net) Mannville wells, as well as five (4.1 net) wells in other areas. Tamarack remains focused on drilling wells which are expected to payout in 1.5 years or less, with a current inventory which could last the Company in excess of eight years.

Total gross proved reserves at December 31, 2017, as evaluated by GLJ, were 51,761 mboe (60.0% oil and liquids), while total gross proved plus probable reserves were 91,462 mboe (61.7% oil and liquids). During 2017, the Company generated finding and development costs of $20.70/boe and $17.88/boe on a total proved and total proved plus probable basis, respectively. Finding, development and acquisition costs, for the same reserve categories, were $27.86/boe and $20.91/boe, respectively.

Developments in 2017

On January 11, 2017, Tamarack closed the Viking Acquisition, consisting of approximately $57.8 million in cash and 90.1 million Common Shares, as well as the assumption of Spur's debt, estimated to be $23.6 million at closing, after accounting for proceeds from the exercise of all outstanding options of Spur, including severance and transaction costs. Based upon Tamarack's share price at closing of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $392 million. The Company's previous credit facility was amended concurrent with the closing of the Viking Acquisition to increase the borrowing base by over 80% to $220 million from $120 million (the "**Credit Facility**"), resulting in estimated debt at that time of approximately $138 million. The transformative Viking Acquisition advances the Company's strategic objective to add concentrated, high netback, light oil-weighted assets to Tamarack that offer quick paybacks across a variety of commodity price environments. The properties acquired through the Viking Acquisition provide a new core area in Alberta and Saskatchewan that complements Tamarack's existing asset base, affords significant operational synergies and expands the Company's long-term oil drilling inventory.

On January 18, 2017, Tamarack provided an operations update, highlights of its 2017 capital program and reaffirmed guidance for 2017. Tamarack achieved record fourth quarter 2016 production of 11,453 boe/d that exceeded previous exit guidance due to continued successful drilling in the Wilson Creek/Alder Flats area of Alberta as well as positive performance from the Penny Assets and Redwater Assets. In addition, the Viking Assets outperformed initial expectations and contributed to a pro-forma 2016 exit production rate of over 18,000 boe/d. Tamarack's 2017 capital expenditures budget was set at $165 to $175 million, annual production expected to average between 19,000-20,000 boe/d (approximately 55-60% liquids), with 2017 exit production estimated between 20,000-21,000 boe/d (approximately 57-62% liquids). Estimated year end 2017 debt to fourth quarter annualized cash flow (including hedges) ratio is anticipated to be below 0.9 times with an estimated $70-75 million of liquidity on the Company's Credit Facility. The Company also announced that Mr. John Leach was appointed as an independent director of Tamarack, expanding the Board to seven directors, six of whom are independent.

On February 27, 2017, Tamarack announced its 2016 year end reserves report (excluding the impact of the Viking Acquisition) and provided an operations update. Organic reserves additions and improving capital efficiencies were achieved despite ongoing weakness in commodity prices due to the success of its drilling program, enhancements to completion techniques and better than expected well performance from the Penny Acquisition and the Redwater Acquisition (collectively, the "**Penny and Redwater Acquisitions**") that closed in July, 2016.

On March 23, 2017, the Company announced its 2016 year-end operating and financial results and an operations update, along with details from the reserves report prepared in accordance with NI 51-101 by GLJ with an effective date of January 31, 2017 (the "**Viking Acquisition Reserves Report**") on the oil assets in the southwestern Saskatchewan and southeastern Alberta Viking play (the "**Viking Assets**") acquired through the combination with privately-held Spur Resources Ltd. ("**Spur**") (the "**Viking Acquisition**") which closed January 11, 2017. In addition, the Company provided a pro-forma reserves summary reflecting the combination of the Viking Acquisition Reserves Report and a modified look-ahead summary performed by GLJ on the reserves disclosure for Tamarack as at December 31, 2016, with an effective date of January 31, 2017 (the "**Pro-Forma Reserves Report**").

On March 23, 2017, Tamarack also announced the appointment of Ian Currie to the Company's Board of Directors, increasing the Board to eight directors.

On May 15, 2017, Tamarack released its financial and operating results for the three months ended March 31, 2017, noting, among other things (i) the completion of the Spur acquisition; (ii) achieving production of 17,796 boe/d with 52% weighted towards oil and NGL; (iii) generating funds from operations of $32.4 million; (iv) investing $63.7 million in capital expenditures to drill 46 (42.4 net) wells; and (v) an increase in its credit facilities to $265 million from $220 million. The Company also noted the completion of three minor tuck-in acquisitions at Tamarack's Penny area during the quarter for $0.8 million; as well as the completion of a $2.1 million acquisition in early May at Wilson Creek.

On June 22, 2017, Robert Spitzer was elected as an independent director of the Company, expanding the Company's Board of Directors to nine directors.

On August 10, 2017, Tamarack released its financial and operating results for the three months ended June 30, 2017, noting, among other things: (i) achieving production of 19,336 boe/d (59% weighted towards oil and NGL) and increasing its 2017 year-end exit production guidance to approximately 22,000 boe/d; (ii) generating funds from operations of $33.7 million; and (iii) investing $19.0 million in capital expenditures to drill, complete, and equip five (4.9 net) Viking oil wells and one (1.0 net) Mannville gas well, and complete and equip five (4.3 net) Viking oil wells and three (3.0 net) Cardium oil wells drilled in Q1/17.

On November 8, 2017, Tamarack released its financial and operating results for the three months ended September 30, 2017, noting, among other things: (i) achieving production of 20,541 boe/d (59% weighted towards oil and NGL); (ii) generating funds from operations of $34.8 million; (iii) investing $74.1 million in capital expenditures to drill 50 (48.6 net) Viking oil wells, eight (8.0 net) Cardium oil wells, one (0.8 net) Ellerslie oil well, one (1.0 net) Mannville gas well, and two (2.0 net) heavy oil wells; (iv) executing on various tuck-in land acquisitions within core areas to bolster Tamarack's footprint, including four separate purchases totaling 145 net sections of land for an aggregate purchase price of $3.4 million and completing a minor tuck-in acquisition within the Company's core Viking area for $5.5 million; and (v) accelerating $10-15 million of first quarter 2018 capital expenditures into December, 2017, with the result that Tamarack's full year 2017 capital budget was increased to $195-198 million.

Developments in 2016

On January 19, 2016, Tamarack announced a capital expenditure budget range of $52 to $57 million for 2016, focused on continued development in its Wilson Creek and Alder Flats areas. This budget was flexible and could be reduced or increased depending on commodity prices in order to protect its balance sheet. The Company also announced that its lenders agreed to maintain its credit facility at $165 million, comprised of a $155 million revolving credit facility and a $10 million operating facility.

On February 29, 2016, Tamarack announced a $38 million bought deal financing to initially reduce bank indebtedness and for general corporate purposes (the "**March 2016 Offering**"). Tamarack issued 14,966,100 Common Shares (including an over-allotment option of 1,952,000 Common Shares) at an issue price of $2.92 per Common Share, generating gross proceeds of $43.7 million. The Company also re-affirmed its 2016 guidance, and indicated that the estimated year-end 12-month trailing debt to cash flow (including hedges) ratio will be reduced to between 0.9 and 1.4 times, which was revised from 1.6 and 2.3 times as a result of the March 2016 Offering. The March 2016 Offering closed on March 18, 2016.

On March 24, 2016, Tamarack announced record fourth quarter 2015 production that averaged 9,968 boe/d (61% liquids), and exceeded exit production guidance of 9,500 to 9,700 boe/d (55-60% liquids) while spending $107.4 million, or 15% less capital than its 2015 guidance of $125 to 130 million. The Company's capital efficiencies improved in 2015 due to permanent drilling and completion design changes, lower services costs and better well performance in the Wilson Creek and Alder Flats areas of Alberta.

On June 20, 2016, Tamarack announced two strategic asset acquisitions that added approximately 1,900 boe/d (75% light oil and NGLs) for total aggregate cash consideration of $85.1 million. One acquisition was comprised of a light oil pool at Penny in Southern Alberta (the "**Penny Acquisition**") and the other was a suite of assets in Redwater and Wilson Creek, Alberta (the "**Redwater Acquisition**"), contiguous with Tamarack's existing Viking and Cardium interests. The Penny and Redwater Acquisitions were partially funded by a bought deal equity financing (the "**July 2016 Financing**").

On July 12, 2016, Tamarack closed the Penny Acquisition and the July 2016 Financing which generated aggregate gross proceeds of approximately $81.6 million, which was used to partially fund the Penny and Redwater Acquisitions. The Company issued 20,110,050 Subscription Receipts at $3.66 each, for gross proceeds of $73.6 million (the "**2016 Subscription Receipts**") plus 1,952,000 Flow-Through Shares at $4.10 each, for gross proceeds of $8.0 million which will be used to incur and renounce Canadian development expenses pursuant to the Income Tax Act (Canada). The 2016 Subscription Receipts were converted into Common Shares on the completion of the Penny Acquisition.

On July 25, 2016, concurrent with the closing of the Redwater Acquisition, Tamarack's new bank line was put into place with a total credit capacity of $120 million, comprised of a $110 million revolving credit facility and a $10 million operating facility. The previous borrowing base of $165 million was reduced to $120 million which reflected an appropriate amount of liquidity for the Company given the prevailing commodity price environment and also to save on fees. The 2016 credit facility was subject to its next 364 day extension by May 26, 2017, and if not extended, the 2016 credit facility would cease to revolve and all outstanding balances would become repayable one year from the extension date (May 26, 2018).

On November 2, 2016, Tamarack announced the most significant transaction in its history: the transformational Viking Acquisition. With the completion of the Viking Acquisition, the Company became an intermediate oil-weighted Cardium and Viking focused growth company with concentrated, high netback, light oil-weighted, low-cost production and one of the top producers in the prolific Viking light oil fairway. The Company's financial strength and flexibility were maintained, while acquiring an extensive drilling inventory of 720 (695 net) total identified low-risk drilling locations with an average light oil and NGL weighting of approximately 70%. Consideration paid by Tamarack for the Viking Acquisition included the issuance of 90,143,581 Common Shares, $57.3 million in cash and assumed debt estimated to be $25.7 million for total consideration of approximately $393.3 million, based on the Company's share price on January 11, 2017 of $3.44 per Tamarack Share, after accounting for proceeds from the exercise of all outstanding options of Spur, and severance and transaction costs.

Tamarack's 2016 production averaged 10,344 boe/d, which was an annual record for the Company along with strong funds from operations of $63.6 million ($0.52 per share basic and diluted). Throughout 2016, the Company drilled a total of 22 (20.9 net) wells, of which 14 (13.6 net) were in the Wilson Creek/ Alder Flats area. Tamarack realized significant reserves and production growth through 2016, while improving its financial position. During the year, the Company drilled, completed and equipped 10 (9.4 net) horizontal Cardium oil wells and two (1.7 net) Cardium oil wells that were spudded in 2015, and spudded four (4.0 net) horizontal Cardium oil wells. In addition, Tamarack drilled, completed and equipped two (2.0 net) Viking oil wells, one (1.0 net) oil well in Penny, one (0.8 net) Mannville gas well and two (2.0 net) heavy oil wells, further contributing to the Company's growth. The operational success realized in 2016, ongoing cost reduction initiatives and the impact of the transformational Viking Acquisition has positioned Tamarack very well to continue delivering accretive growth and long-term sustainability.

Developments in 2015

On March 12, 2015, Tamarack announced that it had disposed of a 49 boe/d producing asset for $2.3 million, before adjustments.

On May 14, 2015, Tamarack announced it had entered into three separate binding purchase and sale agreements with three industry majors to acquire certain assets located in the greater Wilson Creek area for total aggregate cash consideration of approximately $54 million ("**Wilson Creek Cardium Acquisitions**"), and an increase to its capital expenditure budget for 2015 from $130 to $140 million, including the cost of the acquisitions. These acquisitions closed in May and June 2015 for total consideration of $55.0 million prior to adjustments.

Also on May 14, 2015, Tamarack announced a $70.0 million bought deal financing agreement consisting of 13,228,000 subscription receipts (the "**2015 Subscription Receipt**s") priced at $3.78 per Subscription Receipt for gross proceeds of approximately $50.0 million; 3,969,000 Common Shares at an issue price of $3.78 per Common Share for gross proceeds of approximately $15.0 million, and a private placement of 1,205,000 common shares of the Company to be issued on a "CDE flow-through" basis ("**2015 CDE Flow-Through Shares**") at a price of $4.15 per 2015 CDE Flow-Through Share for gross proceeds of approximately $5.0 million. The net proceeds of the 2015 Subscription Receipts were used to pay for a portion of the purchase price under one of the Wilson Creek Cardium Acquisitions and to expand the Company's 2015 capital expenditure program. The net proceeds from the private placement of 2015 CDE Flow-Through Shares were to be used to incur and renounce Canadian development expenditures pursuant to the *Income Tax Act (Canada)*. The financing closed on June 3, 2015, and on June 10, 2015 Tamarack closed the full amount of the over-allotment option, bringing the aggregate gross proceeds to approximately $83.8 million after issuing 15,212,200 2015 Subscription Receipts, 4,564,350 Common Shares and 2,186,800 2015 CDE Flow-Through Shares at the prices listed above.

On July 29, 2015, Tamarack announced that it had increased its credit facility to $165 million from $150 million following its annual review, comprised of a $155 million revolving credit facility and a $10 million operating facility.

On August 24, 2015, Tamarack graduated to the TSX under the symbol TVE. In conjunction with the listing on the TSX, the Common Shares were voluntarily delisted from the TSX Venture Exchange.

On November 10, 2015, Tamarack announced it had closed four minor tuck-in acquisitions in the Wilson Creek area, one in third quarter 2015 and three in fourth quarter 2015 for a total cost of approximately $3.1 million.

Effective December 17, 2015, Noralee Bradley was appointed as an independent director of the Company, expanding the Company's Board to six directors, four of whom were independent directors.

Significant Acquisitions

On January 11, 2017, Tamarack closed the Viking Acquisition, which was a significant acquisition under Canadian securities laws. See "*General Development of the Business – 2017*" for specific details regarding the impact of this transformational transaction and its impact on Tamarack's future growth and position. A Form 51-102F4 Business Acquisition Report in respect of the Viking Acquisition was filed on SEDAR.

On July 12 and July 25, 2016, Tamarack closed the Penny Acquisition and Redwater Acquisition, respectively. See "*General Development of the Business – Developments in 2016*".

On June 15, 2015, Tamarack closed the Wilson Creek Cardium Acquisitions. See *"General Development of the Business – Developments in 2015"* for details regarding the Wilson Creek Cardium Acquisitions.

On September 30, 2014, the Company closed the acquisition of Cardium interests contiguous with Tamarack's existing Cardium interest in Wilson Creek, Alberta, for an aggregate purchase price of approximately $168.5 million prior to certain closing adjustments.

DESCRIPTION OF THE BUSINESS

Business Objectives and Strategy

Since inception, Tamarack's focus has been on the acquisition and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack is committed to long-term growth and its strategic direction is focused on targeting repeatable and relatively predictable "resource-like" plays that provide long-life reserves through either conventional or unconventional production methods. Tamarack evaluates new opportunities by following a disciplined methodology of integrating technical information with expected economic outcomes and risking the expected economic value of each opportunity according to the existing producing analogs in a particular area. The Company employs specific screening criteria to identify and evaluate prospective areas for repeatability, scope, long life and large original oil or gas-in-place per section, which usually suggests sizeable reserves. Tamarack believes that this disciplined approach has and will continue to yield more consistent exploration results over the longer term. In addition, management of Tamarack may pursue assets and/or corporate acquisitions and may undertake divestitures of non-core assets where opportunities exist to enhance the overall value of the organization. The Company also intends to maintain its low cost and efficient structure, both in the field as well as in the general management of the business. Tamarack believes that controlling costs and maintaining cost-efficient operations and a strong balance sheet will ensure it is well positioned to manage through all commodity price cycles.

Since inception, Tamarack has expanded and evolved from a Cardium-focused, junior E&P to an intermediate Cardium oil and Viking oil player, positioned for long-term, sustainable growth. The Company has an extensive inventory of low-risk oil development drilling locations focused in the Cardium and Viking fairways in Alberta and Saskatchewan that are economic at a variety of oil and natural gas prices. The Viking Acquisition has positioned the Company with a very high-quality asset base with low recovery to date that is amenable to advancements in technology which can improve the recoverability of oil and economics. With this portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder return while managing its balance sheet.

Specialized Skills and Knowledge

The Corporation's business requires the application of high levels of technical skill in the areas of geology, geophysics, engineering, drilling and completions, well production operations and finance. Drawing on significant experience in the oil and gas business, Tamarack's management team has a demonstrated track record of bringing together all of the key components needed to run a successful development and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Tamarack to effectively identify, evaluate and execute on value added initiatives.

Exploration Risk Management

Exploration drilling involves substantial risk and no assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. While Tamarack is of the view that its personnel have the skills and that Tamarack will have the necessary resources to achieve its objectives, participation in the exploration for and the development of oil and natural gas has a number of inherent risks. See "*Risk Factors*" for a discussion of exploration risk.

Cyclical and Seasonal Impact of the Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and 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 our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to fix netbacks on production volumes. See "*Other Oil and Gas Information – Forward Contracts*" for our current hedging program.

Competitive Conditions

Tamarack actively competes for reserve acquisitions, exploration leases, licences and concessions, and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Tamarack. Competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Some of Tamarack's customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect Tamarack's ability to sell or supply oil or gas to these customers in the future.

The extensive experience and industry relationships brought by Tamarack's management team enable the Company to compete through bidding on and acquiring additional property rights; discovering new reserves; participating in drilling opportunities; and identifying and entering into commercial arrangements with customers. Tamarack's team has developed and maintained close working relationships with future industry partners and joint operators and believes it has the ability to select and evaluate suitable properties and consummate transactions in a highly competitive environment. Alberta and Saskatchewan provincial land sales are a competitive bid process and in order to compete, Tamarack assesses its interpretation of the value of such lands and on that basis, it may submit a bid.

Field equipment availability is also competitive and Tamarack continues to gain access to it through prior agreements and contacts. With the sharp rise in completions activities across Western Canada in late 2016 and early 2017, costs have risen and competition for crews and equipment is increasing. Hiring and retaining technical and administrative personnel continues to be a competitive process, but Tamarack rewards existing employees and provides opportunities for new staff to participate in the equity of the Company through various long term incentive programs, which helps meet this challenge. The Company believes its distinct competitive advantage is through a combination of its scientific, integrated approach in generating drilling prospects combined with its low-cost operations.

Employees

As at December 31, 2017, Tamarack employed 30 full time professionals and six part-time professionals and made use of 16 consultants at its head office in Calgary, Alberta. The Company also employed five full time field employees located at various field offices in Alberta and Saskatchewan.

Economic Diversity

Tamarack has ensured economic diversity for the Company by not being substantially dependent on any single contract or license, such as a contract to sell the major part of its products or services or to purchase the majority of its goods, services or raw materials, or any franchise or licence or other agreement to use a patent, formula, trade secret, process or trade name upon which the Company's business depends.

Change to Contracts

Tamarack does not reasonably anticipate being affected by renegotiation or termination of contracts or sub-contracts.

Managing Ongoing Capital Requirements

Tamarack anticipates that it will make substantial capital investments for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Tamarack's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs, and while the Company would seek to finance these activities in the most prudent manner possible, it cannot be assured 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 Tamarack. Moreover, future activities may require Tamarack to alter its capitalization significantly. Transactions involving the issuance of securities may be dilutive. The inability of Tamarack to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects. See "*Risk Factors*" for further discussion of capital requirements.

Environmental Policies and Responsibility

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. 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, all of which might have a significant negative impact on earnings and overall competitiveness.

The operations of Tamarack are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Tamarack is committed to meeting its responsibilities to protect the environment and will be taking such steps as required to ensure compliance with environmental legislation in all jurisdictions in which it operates. Tamarack believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue and in continuing to maintain high quality operations, it anticipates making increased expenditures of both a capital and an expense nature as a result of these increasingly stringent environmental protection laws. However, it is not currently possible to quantify any such increased expenditures and it is not anticipated that Tamarack's competitive position will be adversely affected by current or future environmental laws and regulations governing its oil and natural gas operations.

For a further discussion of the environmental regulations affecting the oil and gas industry, see "*Industry Conditions*" and "*Risk Factors*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated as of February 28, 2018. The effective date of the Statement is December 31, 2017 and the preparation date of the Statement is February 15, 2018. In compliance with the requirements of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI-51-101**"), tables below provide the reserves disclosure for Tamarack as at December 31, 2017, independently evaluated by GLJ (the "**GLJ Report**"). Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Tamarack believes is important to the readers of this information.

Disclosure of Reserves Data

Tamarack engaged GLJ to provide an independent evaluation of Proved Reserves and Proved plus Probable Reserves for all of its properties, which are located in Canada in the provinces of Alberta and Saskatchewan. The information set forth below is derived from the GLJ Report, which has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGEH**") and the reserves definitions contained in NI 51-101 and the COGE Handbook.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and conventional natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, NGLs and conventional 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 materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL and conventional natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company'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.

It should not be assumed that the estimates of Future Net Revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Company's crude oil, NGLs and conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and conventional natural gas reserves may be greater than or less than the estimates provided herein. See "*Forward Looking Statements*".

The following tables set forth certain information relating to the Company's oil, natural gas and NGL reserves and the net present value of the estimated Future Net Revenue associated with such reserves as at December 31, 2017 contained in the GLJ Report. These tables summarize the data contained in the GLJ Report, and, as a result, may contain slightly different numbers than the GLJ Report due to rounding.

The GLJ Report was based on certain factual data supplied by the Company and GLJ's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

The Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached hereto as Appendices "A" and "B", respectively.

Reserves Data (Forecast Prices and Costs)

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

FORECAST PRICES AND COSTS

Reserves Category	Crude Oil Lt. & Med. Gross (MBbl)[1]	Crude Oil Lt. & Med. Net (MBbl)[1]	Crude Oil Heavy Gross (MBbl)	Crude Oil Heavy Net (MBbl)	Conventional Natural Gas Gross (MMcf)[2]	Conventional Natural Gas Net (MMcf)[2]	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gross (MBoe)	Total Net (MBoe)
Proved:										
Developed Producing	14,869	13,232	462	390	79,309	71,986	2,766	2,178	31,316	27,797
Developed Non-Producing	781	712	120	98	6,177	5,259	39	32	1,970	1,718
Undeveloped	10,382	9,258	243	197	38,729	35,631	1,396	1,271	18,475	16,665
Total Proved	26,032	23,202	825	685	124,214	112,875	4,200	3,481	51,761	46,181
Probable	21,826	19,361	730	574	86,080	78,162	2,799	2,398	39,701	35,360
Total Proved plus Probable	47,858	42,563	1,555	1,259	210,295	191,037	6,999	5,879	91,462	81,540

Notes:

(1) Immaterial Tight Oil volumes have been included with Light & Medium Crude.
(2) Immaterial CBM volumes have been included in Conventional Natural Gas.
(3) Columns may not add due to rounding.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES AS OF DECEMBER 31, 2017 DISCOUNTED AT (%/YEAR)

FORECAST PRICES AND COSTS

Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)	Unit Value Before Tax Discounted at 10%/Year[1] ($/Boe)	Unit Value Before Tax Discounted at 10%/Year[1] ($/Mcfe)
Proved:							
Developed Producing	763,480	574,178	479,594	418,750	374,925	17.25	2.88
Developed Non-Producing	46,668	37,684	32,659	29,273	26,746	19.01	3.17
Undeveloped	282,396	223,597	165,940	122,192	89,947	9.96	1.66
Total Proved	1,092,544	835,458	678,193	570,215	491,618	14.69	2.45
Probable	1,068,532	703,269	500,394	376,503	295,378	14.15	2.36
Total Proved plus Probable	2,161,076	1,538,728	1,178,587	946,718	786,996	14.45	2.41

Notes:

(1) Unit values are based on Company net reserves.
(2) Columns may not add due to rounding.

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES AS OF DECEMBER 31, 2017 DISCOUNTED AT (%/YEAR)(1,2)

FORECAST PRICES AND COSTS

Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
Proved:					
Developed Producing	763,480	574,178	479,594	418,750	374,925
Developed Non-Producing	46,668	37,684	32,659	29,273	26,746
Undeveloped	225,654	185,262	138,492	101,858	74,478
Total Proved	1,035,802	797,124	650,745	549,881	476,149
Probable	778,001	506,555	355,774	264,508	205,466
Total Proved plus Probable	1,813,803	1,303,679	1,006,519	814,389	681,616

Notes:

(1) It should be noted that the estimated net present values are based on a certain set of assumptions and estimates including those for timing of future capital expenditures, deductibility of tax pools, and applicability of special tax incentives. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of 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.

(2) The prices used to estimate net present values are the average of those used by the largest independent industry reserve evaluators.

(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2017

FORECAST PRICES AND COSTS

Reserves Category	Revenue ($000)	Royalties ($000)	Operating Costs ($000)	Capital Development Costs ($000)	Abandonment & Reclamation Costs ($000)	Future Net Revenue Before Income Tax ($000)	Income Tax ($000)	Future Net Revenue After Income Tax ($000)
Total Proved	2,841,046	309,246	943,612	360,998	134,646	1,092,544	56,741	1,035,802
Total Proved plus Probable	5,333,286	582,523	1,718,743	694,759	176,185	2,161,076	347,273	1,813,803

FUTURE NET REVENUE BY PRODUCTION TYPE AS OF DECEMBER 31, 2017

FORECAST PRICES AND COSTS

Reserve Category	Production Type	Net Revenue Before Income Taxes @ 10% DCF ($000)	Unit Value(4) ($/Boe)	Unit Value(4) ($/Mcfe)
Total Proved	Light and Medium Oil(1)(2)	567,704	18.64	3.10
	Heavy Oil(1)	12,388	16.28	2.71
	Conventional Natural Gas(3)	99,234	6.70	1.12
	Coal Bed Methane	(1,133)	(7.24)	(1.21)
	Total	678,193	14.69	2.45
Proved plus Probable	Light and Medium Oil(1)(2)	992,299	17.91	2.98
	Heavy Oil(1)	25,612	18.32	3.05
	Conventional Natural Gas(3)	161,564	6.59	1.10
	Coal Bed Methane	(889)	(3.96)	(0.66)
	Total	1,178,587	14.45	2.41

Notes:

(1) Including solution gas and other by-products.
(2) Includes immaterial tight oil volumes.
(3) Including by-products but excluding solution gas.
(4) Unit values are based on Company net reserves.
(5) Columns may not add due to rounding.

Definitions and Additional Notes to Reserves Data Tables

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

In the tables set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information*" and elsewhere in this Annual Information Form the following definitions and notes are applicable:

"**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.

"**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.

"**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.

"**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.

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

"**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 sub-divide the developed reserves for the pool between developed producing and developed nonproducing. 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.

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

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

(b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and

(c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

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

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

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

(b) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling, completing and equipping exploratory wells; and

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

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

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

"**gross**" means:

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

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

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

"**net**" means

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

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

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

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

"**Abandonment and reclamation costs**" represent all costs associated with the process of restoring a company's well sites with booked reserves which have been disturbed by oil and gas activities, existing and to be incurred, to a standard imposed by applicable government or regulatory authorities.

Pricing Assumptions

The following tables detail the reference prices and inflation rate assumptions as at December 31, 2017 utilized by GLJ in the GLJ Report for estimating reserves data. GLJ is an independent qualified reserves evaluator. The information included in the summary table below is based on an average of pricing assumptions prepared by three independent external reserves evaluators.

Tamarack's weighted average realized sales prices for the year ended December 31, 2017 were $59.42/Bbl for light and medium crude oil, $46.01/Bbl for heavy oil, $32.38/Bbl for NGL and $2.32/Mcf for natural gas. The average realized price on a total oil equivalent basis was $38.60/Boe.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2017

FORECAST PRICES AND COSTS

Year	Crude Oil WTI Cushing Oklahoma (US$/Bbl)	Crude Oil Edmonton Par Price 40° API (C$/Bbl)	Crude Oil Hardisty Bow River 25° API (C$/Bbl)	Crude Oil Hardisty Heavy 12° API (C$/Bbl)	Natural Gas AECO/NIT Spot(1) (C$/Mmbtu)	NGL Edmonton Propane (C$/Bbl)	NGL Edmonton Butane (C$/Bbl)	NGL Edm. C5+ (C$/Bbl)	Inflation Rate (%/Year)	Exchange Rate (US$/C$)
Forecast										
2018	57.50	68.60	51.23	43.55	2.43	35.69	51.29	72.41	0.70	0.7900
2019	60.90	72.02	57.52	49.90	2.77	35.82	52.29	74.90	2.00	0.8000
2020	64.13	74.48	61.56	54.29	3.19	34.85	53.92	77.07	2.00	0.8167
2021	68.33	78.60	65.27	57.72	3.48	36.07	56.70	81.07	2.00	0.8283
2022	71.19	80.84	67.35	59.67	3.67	35.89	58.32	83.32	2.00	0.8400
2023	73.15	82.83	69.24	61.44	3.76	36.28	59.72	85.35	2.00	0.8433
2024	75.16	85.17	71.39	63.51	3.85	37.39	61.42	87.75	2.00	0.8433
2025	77.17	87.53	73.55	65.56	3.93	38.50	63.08	90.13	2.00	0.8433
2026	79.01	89.66	75.49	67.38	4.02	39.52	64.60	92.32	2.00	0.8433
2027	80.60	91.49	77.12	68.90	4.10	40.37	65.95	94.21	2.00	0.8433
2028	82.20	93.31	78.65	70.24	4.19	41.24	67.26	96.11	2.00	0.8433
2029	83.83	95.15	80.21	71.63	4.28	42.07	68.58	97.99	2.00	0.8433
2030	85.52	97.09	81.82	73.11	4.37	42.95	69.99	99.99	2.00	0.8433
2031	87.22	99.02	83.46	74.55	4.45	43.77	71.38	101.99	2.00	0.8433
2032	88.98	101.01	85.11	76.03	4.53	44.64	72.79	104.04	2.00	0.8433
2033+	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	+2.0%/Yr	2.00	0.8433

Notes:

(1) AECO spot refers to the same-day spot price averaged over the period.

Reserves Reconciliation

The following table sets forth a reconciliation of Tamarack's total Proved, Probable and total Proved plus Probable Reserves as at December 31, 2017 against such Reserves as at December 31, 2016 based on forecast price and cost assumptions:

RECONCILIATION OF GROSS RESERVES[(1)] BY PRINCIPAL PRODUCTION TYPE

FORECAST PRICES AND COSTS

	Lt & Med Crude Oil Proved [(2)] (MBbl)	Lt & Med Crude Oil Probable [(2)] (MBbl)	Lt & Med Crude Oil Proved + Probable [(2)] (MBbl)	Heavy Crude Oil Proved (MBbl)	Heavy Crude Oil Probable (MBbl)	Heavy Crude Oil Proved + Probable (MBbl)	Total Crude Oil Proved (MBbl)	Total Crude Oil Probable (MBbl)	Total Crude Oil Proved + Probable (MBbl)
December 31, 2016	16,839	10,552	27,391	526	477	1,003	17,365	11,029	28,394
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery[(3)]	6,203	6,120	12,323	520	273	792	6,723	6,393	13,115
Technical Revisions	477	(771)	(294)	(246)	(86)	(332)	231	(857)	(626)
Acquisitions	6,480	5,701	12,181	216	64	280	6,696	5,765	12,461
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(341)	223	(118)	(4)	2	(2)	(345)	225	(120)
Production	(3,624)	-	(3,624)	(187)	0	(187)	(3,811)	-	(3,811)
December 31, 2017	26,033	21,826	47,858	825	730	1,555	26,858	22,556	49,413

	NGL Proved (MBbl)	NGL Probable (MBbl)	NGL Proved + Probable (MBbl)	Natural Gas Proved [(4)] (MMcf)	Natural Gas Probable [(4)] (MMcf)	Natural Gas Proved + Probable [(4)] (MMcf)	Total Proved (MBoe)	Total Probable (MBoe)	Total Proved + Probable (MBoe)
December 31, 2016	3,075	2,629	5,703	77,577	56,824	134,401	33,369	23,129	56,498
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery[(3)]	476	286	762	17,767	10,368	28,136	10,159	8,407	18,567
Technical Revisions	307	(505)	(198)	7,613	(1,869)	5,744	1,807	(1,673)	133
Acquisitions	938	423	1,361	42,194	22,231	64,425	14,666	9,893	24,559
Dispositions	(1)	(17)	(18)	(519)	(697)	(1,216)	(88)	(133)	(221)
Economic Factors	(29)	(17)	(46)	(2,572)	(776)	(3,348)	(803)	79	(724)
Production	(565)	-	(565)	(17,846)	-	(17,846)	(7,350)	-	(7,350)
December 31, 2017	4,200	2,799	6,999	124,214	86,080	210,295	51,761	39,701	91,462

Notes:

(1) Company Gross Reserves exclude royalty volumes.
(2) Light & Medium Crude Oil includes immaterial tight oil volumes.
(3) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "*Extensions and Improved Recovery*".
(4) The conventional natural gas volumes include an immaterial amount of coal bed methane production and reserves.
(5) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Tamarack attributes Proved and Probable Undeveloped Reserves and the Company's plans for developing those Undeveloped Reserves. Undeveloped Reserves are attributed by GLJ in accordance with the standards and procedures contained in the COGE Handbook.

Proved Undeveloped Reserves

Proved Undeveloped Reserves are generally those reserves related to drilling spacing units directly off setting producing reserves where there is demonstrated geological continuity. The majority of the Proved Undeveloped Reserves are planned for development over the next three years. However, if the economic climate is not conducive to developing these reserves during this period, Tamarack may, in its discretion, defer the development into the future. There are a number of factors that could result in delays or cancelled development plans. These factors would include, but are not limited to, changing economic and technical conditions, surface access issues, the availability of services and access to pipeline or processing facilities.

Year	Crude Oil Lt. & Med. First Attributed(1),(2) (MBbl)	Crude Oil Lt. & Med. at Year-End(2) (MBbl)	Crude Oil Heavy First Attributed(1) (MBbl)	Crude Oil Heavy at Year-End (MBbl)	Natural Gas First Attributed(1)(3) (MMcf)	Natural Gas at Year-End(3) (MMcf)	Natural Gas Liquids First Attributed(1) (MBbl)	Natural Gas Liquids at Year-End (MBbl)	Total First Attributed(1) (MBoe)	Total at Year-End (MBoe)
2015	1,337	4,635	44	250	14,121	24,968	563	938	4,298	9,985
2016	4,058	6,926	-	183	6,399	26,237	175	1,048	5,300	12,529
2017	5,746	10,382	182	243	16,803	38,729	618	1,396	9,347	18,475

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) Includes immaterial tight oil volumes.
(3) Includes immaterial coal bed methane volumes.

Probable Undeveloped Reserves

Probable Undeveloped Reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a four year timeframe. However, if the economic climate is not conducive to developing these reserves during such timeframe, Tamarack may, in its discretion, defer the development. There are a number of factors that could result in delays or cancelled development plans. These factors would include, but are not limited to, changing economic and technical conditions, surface access issues, the availability of services and access to pipeline or processing facilities.

Year	Crude Oil Lt. & Med. First Attributed(1),(2) (MBbl)	Crude Oil Lt. & Med. at Year-End(2) (MBbl)	Crude Oil Heavy First Attributed(1) (MBbl)	Crude Oil Heavy at Year-End (MBbl)	Natural Gas First Attributed(1)(3) (MMcf)	Natural Gas at Year-End(3) (MMcf)	Natural Gas Liquids First Attributed(1) (MBbl)	Natural Gas Liquids at Year-End (MBbl)	Total First Attributed(1) (MBoe)	Total at Year-End (MBoe)
2015	1,218	6,766	133	386	16,864	35,653	630	1,394	4,792	14,488
2016	2,602	7,772	-	306	12,886	38,172	788	1,908	5,538	16,348
2017	9,462	16,659	234	444	24,503	55,351	649	1,816	14,428	28,143

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) Includes immaterial tight oil volumes.
(3) Includes immaterial coal bed methane volumes.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Tamarack does not anticipate any significant economic factors or significant uncertainties will affect any particular components of its reserves data. However, the Company's reserves can be affected significantly by fluctuations in commodity product pricing, capital expenditures, operating costs, royalty regimes and other government restrictions and well performance that are beyond its control. See "*Risk Factors*" for further details. See Note 10 of the Company's Consolidated Financial Statements for the years ended December 31, 2017 and 2016 for our decommissioning obligations.

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserves estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revision can be either positive or negative.

Future Development Costs

The tables below set out the development costs deducted in the estimation of future net revenue attributable to Proved Reserves and Proved plus Probable Reserves using forecast prices and costs.

FUTURE DEVELOPMENT COSTS ($000)(1)

FORECAST PRICES AND COSTS

Year	Total Proved Reserves ($000)	Total Proved Plus Probable Reserves ($000)
2018	70,037	114,328
2019	117,080	154,073
2020	134,658	183,613
2021	33,427	134,059
2022	5,637	99,007
2023	-	9,508
2024	-	-
2025	-	-
2026	-	-
2027	110	-
2028	-	-
2029	-	-
Subtotal	360,948	694,588
Remainder	50	172
Total	360,998	694,759
10% Discounted	302,034	553,416

Notes:

(1) Future development costs shown are associated with booked reserves in the GLJ Report and do not necessarily represent the Company's full exploration and development budget.

Tamarack typically has available three sources of funding to finance its capital expenditure program: internally generated adjusted funds flow, debt financing when appropriate and new equity issues, if available on favourable terms.

The Company expects to fund its 2018 capital program with internally generated adjusted funds flow, cash resources on hand, and potentially debt, although the program has been structured to maintain balance sheet strength. Management does not anticipate that these costs of funding will materially affect Tamarack's disclosed reserves and future net revenues nor make the development of any of its properties uneconomic.

Other Oil and Natural Gas Information

The following is a description of Tamarack's principal oil and natural gas properties that are on production or under development as at March 8, 2018 and incorporates the assets acquired in the Viking Acquisition. Information in respect of current production is average production, net to its working interest, except where otherwise indicated. Reserves noted are company interest reserves which include both working interest and royalty interest values.

See below for a map indicating the position of these principal properties.

Tamarack's oil and gas properties are all onshore and primarily located in the provinces of Alberta and Saskatchewan largely targeting the Cardium oil and Viking oil plays. A summary of the important oil and gas properties by area as at December 31, 2017 follows. Tamarack's producing and non-producing wells by area together with the working interest are contained in a table following these property descriptions.

Alberta Cardium Light Oil:

Wilson Creek/Alder Flats/Pembina

Tamarack has interests in 336.1 (266.0 net) sections of land in the Wilson Creek/Alder Flats/Pembina area of Alberta. At year-end 2017, the Company had proved developed producing reserves of 13,148 mboe and proved plus probable reserves of 37,073 mboe that were booked to 201 (176.6 net) producing Cardium and 120 (81.4 net) wells producing from other zones including a 52% interest in the Pekisko Gas Unit. Proved undeveloped drilling locations of 54 (42.0 net) were included in the evaluation. Tamarack operates: two pipeline-connected oil batteries – one with oil capacity of 5,000 bbl/d and the other with 1,000 bbl/d - a 52% owned 30 mmcf/d gas plant and a 100% ownership in a 13 mmcf/d gas plant. The two operated oil batteries are pipeline-connected to the Pembina Pipeline.

Garrington/Lochend

Tamarack has interests in 13.5 (7.8 net) sections of land in the Garrington and Lochend areas of Alberta. At year-end 2017, proved developed producing reserves of 631 mboe and proved plus probable reserves of 2,531 mboe were booked 24 (14.1 net) producing wells. Proved undeveloped drilling locations of 6 (4.5 net) were included in the evaluation.

Viking Light Oil:

Viking Areas – Veteran/Consort, AB

Tamarack has interests in 343.1 (311.4 net) sections of land in the Veteran and Consort areas of southeast Alberta. Proved developed producing reserves of 4,122 mboe and proved plus probable reserves of 16,803 mboe were booked to 254 (234.0 net) producing wells. Proved undeveloped drilling locations total 104 (99.7 net). Tamarack's total estimated inventory is approximately 533 gross locations. Across 2017, Tamarack invested in the Veteran area infrastructure, including the expansion of an existing oil battery to 10,000 bbls/d of emulsion processing capacity and the addition of water handling facilities to support area development. In addition to this expansion and other existing oil processing infrastructure, Tamarack has a 34.2% working interest in an operated Gas Plant in Consort, AB.

Viking Areas – North Hoosier/Milton/Coleville, SK

Tamarack has interests in 181.9 (153.0 net) sections of land in the North Hoosier,Milton and Coleville areas of southwest Saskatchewan. Proved developed producing reserves of 5,636 mboe and proved plus probable reserves of 14,669 mboe were booked to 269 (202.2 net) producing wells. Proved undeveloped drilling locations total 57 (49.9 net). Tamarack's total estimated inventory is approximately 200 gross location. Tamarack also owns and operates significant oil and gas pipeline infrastructure, multiple batteries and compressors in the area.

Viking Area – Redwater, AB

Tamarack has interests in 66.6 (58.0 net) sections of land in the Redwater area of Alberta. Proved developed producing reserves of 1,543 mboe and proved plus probable reserves of 7,028 mboe were booked to 160 (150.1 net) producing wells. Proved undeveloped drilling locations of 58 (52.7 net) were included in the evaluation. Tamarack processes all area production through operated facilities including a 10,000 bbls/d emulsion processing oil battery.

Lethbridge Light Oil:

Barons Light Oil - Penny Area

Tamarack has interests in 179.6 (149.4 net) sections of land in the Penny area of Southern Alberta featuring a large light oil pool under active waterflood, with only approximately 10% recovered to date. Proved developed producing reserves of 5,383 mboe and proved plus probable reserves of 9,608 mboe were booked to 336 (210.7 net) producing wells. Proved undeveloped drilling locations of 14 (14.0 net) were included in the evaluation. Key infrastructure consists of four 100% owned oil batteries with combined oil capacity of over 2,000 bbls/d, two 100% owned gas plants with combined 12.5 mmcf/d capacity, multiple injectors and various field compression equipment.

Saskatchewan Heavy Oil:

Heavy Oil – Hatton/Salt Lake

Tamarack has interests in 61.9 (61.5 net) sections of land in the Hatton and Salt Lake areas of Saskatchewan. Proved developed producing reserves of 350 mboe and total proved plus probable reserves of 1,201 mboe were booked to 27 (25.5 net) producing wells. Three (3.0 net) proved undeveloped drilling locations were included in the evaluation. Tamarack operates a 1,200 bbl/d oil battery in the Hatton area. All reserves are based on Company Interest reserves with no royalty burdens applied.

Oil and Natural Gas Wells

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

Area[1]	Crude Oil Producing (Gross)	Crude Oil Producing (Net)	Crude Oil Non-prod[2] (Gross)	Crude Oil Non-prod[2] (Net)	Natural Gas Producing (Gross)	Natural Gas Producing (Net)	Natural Gas Non-prod[2] (Gross)	Natural Gas Non-prod[2] (Net)
Cardium Oil Areas	276.0	235.6	60.0	52.3	145.0	92.0	63.0	35.8
Viking Oil Areas	677.0	604.1	211.0	195.7	140.0	110.8	210.0	181.9
Penny Oil Area	97.0	94.1	32.0	30.5	263.0	137.8	89.0	74.3
Heavy Oil Area	29.0	29.0	15.0	14.7	11.0	10.0	15.0	14.5
Other	14.0	7.5	7.0	6.1	360.0	328.3	105.0	60.1
Total	1093.0	970.3	325.0	299.3	919.0	678.9	482.0	366.6

Notes:

(1) All of Tamarack's wells are located onshore in Alberta and Saskatchewan.
(2) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Developed and Undeveloped Lands

Province	Undeveloped Acres (Gross)	Undeveloped Acres (Net)	Developed Acres (Gross)	Developed Acres (Net)	Total Acres (Gross)	Total Acres (Net)
Alberta	406,953	328,864	498,018	91,859	904,971	720,723
Saskatchewan	47,279	45,188	126,890	109,601	174,168	154,789
Total	454,232	374,052	624,908	201,460	1,079,139	875,512

Tamarack had 454,232 gross acres (183,821 gross hectares) and 374,052 net acres (151,373 net hectares) of undeveloped land as at December 31, 2017 located in Alberta and Saskatchewan. The Company has no work commitments currently scheduled on these lands. Tamarack expects that 35,655 gross (34,889 net) acres will expire during 2018. The majority of these expiries are on lands that are not part of Tamarack's go forward plans. The Company reviews the economic viability of these undeveloped properties on the basis of pricing and capital availability and allocation. There is no guarantee that commercial reserves will be discovered or developed on these properties.

In calculating gross and net acreage, Tamarack counts an acreage twice if the Company holds interests in separate prospective formations under the same surface area under separate leases. It counts an acreage once if Tamarack holds interests in separate prospective formations under the same surface area under a single lease. Tamarack has only one section with two prospective formations under one lease and the acreage was counted once.

Forward Contracts

Tamarack is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Tamarack may use certain derivative financial instruments and foreign exchange contracts to reduce its exposure to fluctuations in commodity prices, increase the certainty of funds from operations and to protect acquisition and development drilling economics. Such financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company may be exposed to losses in the event of default by the counterparties to these derivative instruments, but it manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties. Tamarack's Board of Directors reviews all derivative and foreign exchange contracts quarterly to ensure such transactions are conducted within risk management tolerances.

A list of the Company's derivative financial instruments as at December 31, 2017 and those acquired through the Viking Acquisition, can be found in note 5(d) of the Notes to the Consolidated Financial Statements for the years ended December 31, 2017 and 2016.

Tax Horizon

Tamarack was not required to pay income taxes during the year ended December 31, 2017. Based on a strategy of reinvesting all internally generated cash flow in an exploration and development program and based on the commodity prices used in the GLJ Report, Tamarack estimates that it will not be required to pay income taxes until sometime after 2020.

Costs Incurred

The following table summarizes Tamarack's property acquisition costs, exploration costs and development costs, net of property dispositions, for the year ended December 31, 2017.

Expenditures for the Year Ended December 31, 2017	Amount ($000)
Property acquisition costs – Unproved properties (1)	1,708
Property acquisition costs – Proved properties (2)	6,213
Corporate acquisition costs	391,512
Exploration costs (3)	2,022
Development costs (4,5)	185,565
Other	3,006
Total	590,026

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(5) Net of drilling credits.

Exploration and Development Activities

The following table sets forth the gross and net development wells completed by Tamarack during the financial year ended December 31, 2017.

Type of Well	Development Wells (Gross)	Development Wells (Net)
Light and Medium Oil	120.0	114.3
Heavy Oil	10.0	9.1
Natural Gas	3.0	3.0
Service	1.0	1.0
Dry and Abandoned	0.0	0.0
Stratigraphic Test	0.0	0.0
Total	134.0	127.4

In 2018, and contingent on commodity price levels and associated well economics, the Company expects to drill approximately 69 (67.6 net) Viking light oil wells in the Veteran area of Alberta, approximately 23 (20.7 net) Viking light oil wells in the North Hoosier/Milton area of Saskatchewan, approximately 19 (17.8 net) Cardium light oil wells at its Wilson Creek/Alder Flats area in Alberta, approximately three (3.0 net) light oil wells at the Penny area of Alberta and approximately ten (9.7 net) wells in other areas. The Company will continue to focus on drilling wells that will generate the highest rates of return. See "*Recent Developments*".

Finding, Development and Acquisition Costs

The following table summarizes Tamarack's finding and development and finding, development and acquisition costs for the periods indicated.

($/Boe)[1,2,3,4]	2017	2016	2015	3-Year Average
Proved Reserves				
Finding, development and acquisition cost	27.86	14.68	13.26	21.31
Finding and development costs	20.70	14.44	10.95	17.35
Acquisition costs	33.33	14.74	15.04	23.67
Proved plus Probable Reserves				
Finding, development and acquisition cost	20.91	11.34	7.20	16.08
Finding and development costs	17.88	7.20	(4.06)	13.59
Acquisition costs	23.15	11.57	11.46	17.23

Notes:

(1) Finding, development acquisition ("**FD&A**") costs are calculated by dividing total capital by reserve additions during the applicable period. Total capital includes both capital expenditures incurred and changes in future development capital required to bring proved undeveloped reserves and probable reserves to production during the applicable period. Reserve additions is calculated as the change in reserves from the beginning to the end of the applicable period excluding production.

(2) Including changes in future development capital expenditures.

(3) While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of finding and development ("**F&D**") costs, FD&A costs have been presented because acquisitions and dispositions can have a significant impact on the Company's ongoing reserve replacement costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. F&D costs both including and excluding acquisitions and dispositions have been presented above.

(4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total F&D costs related to reserves additions for that year.

(5) F&D costs are not necessarily calculated in the same manner by all issuers. Accordingly, they should not be used to make comparisons amongst different issuers. See "*Conventions*".

Production Estimates

The following table sets out the first year production forecast of volumes of Tamarack's working interest (Company Gross) production for each product type estimated by GLJ for the year ended December 31, 2017, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosures of Reserves data*".

	Gross Lt. & Med. Crude Oil (bbl/d)(1)	Gross Heavy Crude Oil (bbl/d)	Gross Conventional Natural Gas (Mcf/d)(2)	Gross Natural Gas Liquids (bbl/d)	Gross Barrel of Oil Equivalent (boe/d)
Total Proved					
Alder/Wilson	2,752	-	21,498	1,003	7,338
Consort/Veteran	3,784	-	5,555	84	4,795
Other Properties	3,346	888	17,397	319	7,453
Total	9,882	888	44,450	1,406	19,586
Total Proved plus Probable					
Alder/Wilson	3,324	-	23,325	1,087	8,299
Consort/Veteran	4,867	-	6,535	99	6,056
Other Properties	3,906	1,313	19,023	340	8,728
Total	12,097	1,313	48,883	1,526	23,083

Notes:

(1) Includes immaterial tight oil volumes.
(2) Includes immaterial coal bed methane volumes.
(3) Columns may not add due to rounding.

2017 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2017, Tamarack's share of average daily production volume, prior to royalties, the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

	3 Months Ended Mar 31/17	3 Months Ended Jun 30/17	3 Months Ended Sep 30/17	3 Months Ended Dec 31/17	12 Months Ended Dec 31/17
Average Daily Production[1]					
Light and Medium Oil (Bbl/d)	7,891	9,481	10,108	12,189	9,929
Heavy Oil (Bbl/d)	484	453	603	500	511
Natural Gas (Mcf/d)	45,852	47,696	49,987	51,956	48,893
NGLs (Bbl/d)	1,779	1,453	1,499	1,459	1,547
Total (Boe/d)	17,796	19,336	20,541	22,807	20,136
Average Net Production Prices Received					
Light and Medium Oil ($/Bbl)	63.02	55.58	53.43	65.08	59.42
Heavy Oil ($/Bbl)	44.64	43.80	46.26	48.97	46.01
Natural Gas ($/Mcf)	2.89	3.01	1.62	1.89	2.32
NGLs ($/Bbl)	26.46	29.39	30.76	44.03	32.38
Total ($/Boe)	39.25	37.91	33.83	42.97	38.60
Royalties Paid					
Light and Medium Oil ($/Bbl)	5.64	6.41	6.08	5.90	6.01
Heavy Oil ($/Bbl)	11.63	8.09	9.85	10.63	9.95
Natural Gas ($/Mcf)	0.27	0.19	0.08	0.10	0.16
NGLs ($/Bbl)	6.37	1.95	3.09	6.29	4.51
Total ($/Boe)	4.15	3.97	3.73	4.03	3.96
Production Costs[2,3,4]					
Light and Medium Oil ($/Bbl)	19.41	16.56	16.23	13.96	16.23
Heavy Oil ($/Bbl)	23.24	30.77	27.73	32.67	28.80
Natural Gas ($/Mcf)	0.84	1.17	0.98	0.95	0.99
NGLs ($/Bbl)	0.00	0.00	0.00	0.00	0.00
Total ($/Boe)	11.42	11.85	11.26	10.40	11.19
Netback Received					
Light and Medium Oil ($/Bbl)	37.97	32.60	31.12	45.22	37.17
Heavy Oil ($/Bbl)	9.77	4.94	8.68	5.67	7.26
Natural Gas ($/Mcf)	1.78	1.65	0.55	0.84	1.18
NGLs ($/Bbl)	20.09	27.44	27.67	37.74	27.87
Total ($/Boe)	23.68	22.09	18.84	28.54	23.45

Notes:

(1) Before the deduction of royalties.
(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.
(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(4) Production costs attributable to NGLs have been included in the light and medium oil and natural gas production cost amounts.

The following table sets forth the average daily production volumes for the year ended December 31, 2017 for each of the important properties comprising Tamarack's assets.

Property	Crude Oil Lt & Med (Bbl/d)	Crude Oil Heavy (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Total (Boe/d)
Cardium Oil Area	3,613	-	26,700	1,337	9,400
Viking Oil Area	5,304	-	15,841	181	8,125
Penny Oil Area	900	-	2,119	7	1,260
Heavy oil Area	92	511	729	-	724
Other	21	-	3,504	22	627
Total	9,929	511	48,893	1,547	20,136

Notes:

(1) The Viking Acquisition closed on January 11, 2017 and as such, volumes above reflect production from those assets after that date.

DESCRIPTION OF SHARE CAPITAL

Tamarack is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As at March 8, 2018, there are 228,608,714 Common Shares and no preferred shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attached to such securities.

Common Shares

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Company, except meetings at which only holders of a specified class of shares are entitled to vote; (ii) subject to the prior rights and privileges attaching to any other class of shares of the Company, the right to receive any dividend declared by the Company; and (iii) subject to the prior rights and privileges attaching to any other class of shares of the Company, the right to receive the remaining property and assets of the Company upon dissolution.

Preferred Shares, Issuable in Series

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. The preferred shares may, at any time and from time to time, be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be determined by resolution of the Board of Directors. Subject to the provisions of the ABCA, the Board of Directors may by resolution fix, from time to time before the issue thereof, the designation, rights, privileges, restrictions and conditions attaching to each series of the preferred shares.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the trading symbol "TVE". The following table sets forth the market price ranges and the trading volumes of the Common Shares for the financial year ended December 31, 2017 and as at March 8, 2018:

Month	High ($)	Low ($)	Volume
January 2017	3.59	3.20	48,722,367
February 2017	3.40	2.92	14,750,809
March 2017	3.03	2.60	17,294,892
April 2017	3.16	2.54	13,166,897
May 2017	2.65	2.17	28,685,707
June 2017	2.41	1.96	13,586,778
July 2017	2.45	2.03	5,619,711
August 2017	2.35	1.98	8,245,138
September 2017(1)	2.88	2.25	11,396,737
October 2017	3.06	2.49	12,919,985
November 2017	3.15	2.52	15,955,705
December 2017	2.89	2.51	6,130,791
January 2018	3.09	2.74	12,807,980
February 2018	2.86	2.31	9,206,048
March 1-7, 2018	2.68	2.41	3,291,518

Prior Sales

During the financial year ended December 31, 2017, the Company granted an aggregate of 140,000 options, each option entitling the holder thereof to acquire one Common Share, the particulars of which are set forth in the following table:

Date of Option Grant	Number(1)	Exercise Price ($)
January 6, 2017	50,000	$3.38
March 17, 2017	50,000	$2.82
April 17, 2017	40,000	$2.77
Total Issued:	140,000	$3.01

Notes:

(1) Each Option entitles the holder thereof upon exercise to acquire one Common Share in accordance with the option plan of the Company.

During 2017, a total of 812,000 options were exercised, and 99,000 options expired or were forfeited.

Except as set forth below, no additional unlisted securities of the Company were issued during the financial year ended December 31, 2017.

RSU Grants

In the year ended December 31, 2017, the Company granted 2,785,215 restricted share units ("**RSUs**") pursuant to its restricted share unit plan (the "**RSU Plan**"). 28,000 RSUs were exercised during 2017. As of December 31, 2017, there were 5,818,382 RSUs outstanding. Each RSU entitles the holder thereof upon settlement to receive one Common Share in accordance with the RSU Plan. An RSU holder may also elect to have RSUs settled in exchange for a payment by the Company of a cash amount per RSU equal to the closing price of the Common Shares before the distribution date for the settlement of the RSUs, provided; however, that the Company has the sole discretion to consent or refuse the election to receive cash. The RSU grants vest one-third on the first, second and third anniversary of the date of grant.

Date of RSU Grant	Number	Exercise Price ($)
January 6, 2017	60,000	$3.53
January 16, 2017	73,500	$3.40
March 17, 2017	50,000	$2.82
March 23, 2017	8,775	$2.67
April 17, 2017	40,000	$2.77
May 1, 2017	30,000	$2.63
August 9, 2017	5,000	$2.08
September 11, 2017	20,000	$2.41
November 29, 2017	251,940	$2.58
December 27, 2017	2,246,000	$2.80
Total Issued:	2,785,215	$2.81

TAC Preferred Shares

On June 17, 2010, pursuant to the Restructuring Transaction, 2,024,273 preferred shares in the capital of PrivateCo were exchanged by certain former shareholders of PrivateCo for 2,024,273 preferred shares ("**TAC Preferred Shares**") of TAC (formerly Tango Acquisition Corp.). Under the terms and conditions of an exchange agreement between the Company and each holder of TAC Preferred Shares, the Company has the option to purchase each TAC Preferred Share for either a cash payment reflecting the "in-the-money" amount or equivalent Common Share consideration under certain circumstances including (a) the occurrence of a "change of control" of Tamarack (as defined in Tamarack's option plan), (b) the holder ceasing to act as a director, officer, employee or consultant of Tamarack for any reason other than death or permanent disability, (c) the death or disability of the holder of TAC Preferred Shares, and (d) the Common Shares trading at a 300% premium to the exercise price of $3.12 per Common Share equivalent over any consecutive 20 day trading period (being days on which at least a board lot of Common Shares trades on the TSX-V or such other stock exchange on which the greatest number of Common Shares are traded). As at March 8, 2018, there are 1,155,007 TAC Preferred Shares issued and outstanding. Assuming all TAC Preferred Share exchange rights are exercised, Tamarack would issue 1,110,584 Common Shares.

DIVIDENDS

The Company has not declared or paid any dividends on the Common Shares in any of the three most recent financial years. It is not expected that the Company will pay any dividends in the near future but will review that policy from time to time as circumstances warrant. The Company currently intends to retain future earnings, if any, to finance future operations, the expansion of Tamarack's business and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board of Directors and will depend on, among other things, the Company's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board of Directors may deem relevant.

In addition to the foregoing, the Company's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness, including the Credit Facility, that the Company has incurred or may incur in the future.

DIRECTORS AND EXECUTIVE OFFICERS

The following table lists the names of the directors and officers, their municipalities of residence, positions and offices with the Company and principal occupations. All directors have been elected to serve as such until the Company's next annual meeting of shareholders, or until his or her successor is duly elected, unless his or her office is vacated earlier in accordance with the by-laws of the Company or applicable law.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Floyd Price[(3)] *Texas, United States*	Director since June 17, 2010	Mr. Price is an independent businessman and is currently a director of Cimarex Energy Co., a U.S.-based oil and gas exploration and production company listed on the New York Stock Exchange, since December 2012. He was previously a director of Gastar Exploration Ltd., a U.S.-based oil and gas exploration and production company listed on the NYSE Amex, from June 2010 to January 2013. Mr. Price has served on the boards of several privately-held oil and gas focused entities, and previously was Executive Vice President of Apache Corporation from February 2003 to October 2009.
Jeffrey Boyce[(1)(2)] *Alberta, Canada*	Director since October 9, 2013	Mr. Boyce is a senior oil and gas executive with over 35 years of domestic and international experience in building, financing and managing public oil and gas companies. He is currently President of Evsam Holdings Ltd., a privately held investment company, since October 2013. Previously he served as Executive Chairman and Director of PetroAmerica Oil Corp. a TSX-V company, from September 2009 until its acquisition by Gran Tierra Energy Inc. in January 2016. Prior thereto, Mr. Boyce was a co-founder, Senior Executive and Director of Sure Energy Inc., Clear Energy Inc. and Vermilion Resources.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Noralee Bradley[(3)(4)] *Alberta, Canada*	Director since December 17, 2015	Ms. Bradley is a partner at the national law firm of Blake Cassels & Graydon LLP, which she joined in September 2017, Previously she had been with Osler, Hoskin & Harcourt LLP, since January 2006. Her practice is focused on mergers and acquisitions, financings and board governance. Ms. Bradley was a member of the executive committee of the Institute of Corporate Directors, Calgary Chapter from 2010-2016 (serving as Chair in 2015-2016), has served on the Executive and Compensation Committees of Osler (2012-2016) and was previously a director of Angle Energy Inc., a TSX listed company, from June 2004 until its acquisition in December 2013. Prior to joining Osler, Hoskin & Harcourt LLP, Ms. Bradley was a partner with Bennett Jones LLP, a national law firm. Ms. Bradley served as Corporate Secretary of the Company until December 17, 2015.
Ian Currie[(2)(4)] *Alberta, Canada*	Director since March 22, 2017	Mr. Currie is a professional engineer with over 30 years of oil and gas experience. He is currently the President and CEO of Spur Petroleum Ltd., a privately-held oil and gas exploration and production company. Previously he served as President and CEO of Spur Resources, Ltd. from 2006 until its acquisition by Tamarack in January, 2017. Prior thereto, he was Vice President, Operations at Profico Energy Management from its inception in 2000 until its acquisition in 2006, and held senior operational roles with Renaissance Energy Ltd. since 2002.
John Leach[(1)(3)] *Alberta, Canada*	Director since January 18, 2017	Mr. Leach is a Chartered Professional Accountant with over 24 years of oil and gas experience. He is currently the Senior Vice President & Chief Financial Officer of Crew Energy Inc., a position he has held since Crew's spin-out from Baytex Energy Ltd. in 2003. Previously, Mr. Leach was a founding member of Baytex Energy Ltd. since 1993, serving in the finance department in increasing roles of responsibility culminating as its Vice President, Finance from 1998 to 2003. Mr. Leach has been a CPA since 1991 and is a graduate of the University of Saskatchewan.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
David R. MacKenzie(1)(2) *Alberta, Canada*	Director since June 17, 2010	Mr. MacKenzie is an independent businessman and long-time President of the privately-held Lincoln Group of Companies, which has been making private equity investments in the oil and gas, technology and real estate industries, since 1990. While leading the Lincoln Group of Companies, Mr. MacKenzie has occasionally served as a director and/or executive officer of certain companies in which the Lincoln Group has invested in including having served as President of Avant Garde Energy Corp. from September 2009 until its acquisition by the Company in June 2010. Mr. MacKenzie has also served as a director for various publicly-held companies.
Dean Setoguchi(1) *Alberta, Canada*	Director since June 17, 2010	Mr. Setoguchi is a Chartered Professional Accountant and currently serves as the Senior Vice President, Liquids Business Unit of Keyera Corp., a TSX listed energy midstream business, since April 2014. Prior thereto, Mr. Setoguchi was Chief Financial Officer of Laricina Energy Ltd., a privately-held oil sands company, from October 2012 to March 2014. Prior thereto, Mr. Setoguchi was Vice President and Chief Financial Officer of Keyera Corp. from September 2008 to October 2012.
Brian Schmidt *Alberta, Canada*	President and Chief Executive Officer Director since June 17, 2010	President and Chief Executive Officer of the Company. He is currently a member of the Board of Governors of the Canadian Association of Petroleum Producers and is the Alberta Executive Policy Group Chairman. He is a director of Aspenleaf Energy Limited, a private company and is an advisor to the Indian Oil & Gas Co-Management Board. Prior thereto, he was President, Chief Executive Officer and a director of privately-held Tamarack Valley Energy Ltd., a predecessor entity to the Company, from August 2009 to June 2010.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Robert Spitzer(3)(4) *Alberta, Canada*	Director Since June 22, 2017	Mr. Spitzer is an experienced professional in the upstream oil and gas field with over 34 years of industry tenure. Mr. Spitzer is currently an independent businessman. He was previously the Executive Vice President of Apache Kitimat Upstream from 2013-2015 and the Vice President New Ventures of Apache Canada Ltd., a wholly-owned subsidiary of Apache Corporation, from 2005-2012. Prior thereto, Mr. Spitzer held a variety of exploration and development-based positions with Apache Canada Ltd. and Shell Canada Ltd. He has a Master of Science in Remote Sensing (Geologic Application) degree and a Bachelor of Science (Honours) in Geology and Geography, both from McMaster University.
Ron Hozjan *Alberta, Canada*	Vice President, Finance and Chief Financial Officer	Mr. Hozjan is a Chartered Professional Accountant with over 30 years of oil and gas experience has been Vice President, Finance and Chief Financial Officer of the Company since June 2010, and had served as a director of the Company from June 2010 to June 2011. Previously, he was the Chief Financial Officer of Vaquero Resources Ltd. which was acquired by RMP Energy Ltd. Prior thereto, he was Vice President Finance and Chief Financial Officer at a predecessor firm, Vaquero Energy Ltd., which grew successfully before merging with Highpine Oil & Gas Limited. Previously, he held various senior finance positions at Storm Energy and Renaissance Energy.
Dave Christensen *Alberta, Canada*	Vice President, Engineering	Mr. Christensen has been Vice President, Engineering of the Company since April 2014. Prior thereto, he spent five years at Bonavista Energy Corp with the last four as Development Engineering Manager - West Region, an area in which all of Tamarack's Cardium assets are situated. While at Bonavista, Mr. Christensen managed the drilling of over 300 horizontal wells, and evaluated and closed on more than $1 billion of acquisitions. Previously, he held various management positions at Norcen Energy, Storm Energy, and Piper Energy.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Ken Cruikshank *Alberta, Canada*	Vice President, Land	Mr. Cruikshank has been the Vice President, Land of the Company since June 2010 and was appointed an officer of the Company on October 4, 2013. Prior thereto, he was Vice President Land of Vaquero Resources Ltd., which was acquired by RMP Energy Ltd., as well as at a predecessor firm, Vaquero Energy Ltd., which successfully merged with Highpine Oil & Gas Ltd. Previously, Mr. Cruikshank spent seven years as Vice President Land of Beau Canada Exploration Ltd.
Scott Reimond *Alberta, Canada*	Vice President, Exploration	Mr. Reimond was appointed Vice President, Exploration of the Company in October 2012. He had previously been the Exploration Manager of the Company since June 2010 and the Exploration Manager of privately-held Tamarack Valley Energy Ltd. from September 2009 to June 2010. Prior to Tamarack, he was a Senior Geologist with Spearpoint Energy up until its sale to NAL Oil & Gas Trust in 2009, and previously was a Senior Geologist with Rock Energy.
Kevin Screen *Alberta, Canada*	Vice President, Production and Operations	Mr. Screen is a professional engineer and has been the Vice President, Production and Operations of the Company since September 2011. Prior thereto, he held the positions of Business Unit Manager, Asset Team Leader, and Production Engineer at Apache Canada Ltd. from September 2002 to September 2011.
Sony Gill *Alberta, Canada*	Corporate Secretary	Mr. Gill is a partner at the law firm of McCarthy Tétrault LLP since January 2008, practicing primarily in the areas of corporate finance, mergers and acquisitions.

Notes:

(1) *Member of the Board of Directors' audit committee.*
(2) *Member of the Board of Directors' reserves committee.*
(3) *Member of the Board of Directors' compensation and governance committee.*
(4) *Member of the Board of Directors' health, safety and environment committee.*

As of February 26, 2018, the directors and executive officers of the Company as a group beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 4,649,572 Common Shares, representing approximately 2.04% of the Common Shares issued and outstanding on a non-diluted basis.

Cease Trade Orders

To the knowledge of management, no director or executive officer of the Company is, as at the date of this AIF, or has been, within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company) that: (i) was subject to an order (as defined below) 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 an order 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 director, chief executive officer or chief financial officer.

For the purposes of this part, "order" means: (i) a cease trade order; (ii) an order similar to a cease trade order; or (iii) an order that denied the relevant company access to any exemption under securities legislation, in each case, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Except as described below, to the knowledge of management, no director or executive officer of the Company, nor any shareholder holding a sufficient number of Common Shares to materially affect the control of the Company: (i) is, or has been within the 10 years before the date of this AIF, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this AIF, 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 such person's assets.

Dave Christensen was Vice President, Corporate Development of Piper Resources Ltd. ("**Piper**") from January 2008 until August 2008. On February 17, 2008, Piper obtained a creditor protection order under the *Companies' Creditors Arrangement Act* (Canada) from the Court of Queen's Bench of Alberta. On August 14, 2008, Piper received notice of a Petition for Receiving Order that Piper be adjudged bankrupt. Subsequently, on August 18, 2008, the Court of Queen's Bench of Alberta granted a Bankruptcy Order in respect of Piper.

Dean Setoguchi was Senior Vice President and Chief Financial Officer of Laricina Energy Ltd. ("**Laricina**") from November 2012 until April 2014. Laricina voluntarily entered into *Companies' Creditors Arrangement Act* ("**CCAA**") proceedings and obtained an order from the Court of Queen's Bench of Alberta, Judicial Centre of Calgary for creditor protection and a stay of proceedings effective March 26, 2015. Laricina was granted a final court order from the Court of Queen's Bench of Alberta, Judicial Centre of Calgary on January 28, 2016 exiting from protection under the CCAA concluding the stay of proceeding against Laricina and its subsidiaries effective upon the filing of a certificate by the court appointed monitor under the CCAA which occurred February 1, 2016.

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

Penalties or Sanctions

To the knowledge of management, no director or executive officer of the Company, nor any shareholder holding a sufficient number of Common Shares to materially affect the control of the Company, has: (i) been subject to 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) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in deciding whether to make an investment decision.

Conflicts of Interest

The directors or officers of Tamarack may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with Tamarack. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with Tamarack to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

AUDIT COMMITTEE INFORMATION

The purpose of the Company's audit committee ("**Audit Committee**") is to provide assistance to the Board of Directors in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Company. It is the objective of the Audit Committee to maintain open communication among the Board of Directors, the independent auditors and the financial and senior management of the Company.

Audit Committee Mandate

Tamarack's Audit Committee mandate sets out the committee's purpose, organization, duties and responsibilities. A copy of the mandate is attached hereto as Appendix "C".

Composition of Audit Committee

Tamarack's Audit Committee is comprised of Dean Setoguchi, David R. MacKenzie, John Leach and Jeffrey Boyce, all of whom are financially literate, as such term is defined in NI 52-110, and all of whom are considered independent under NI 52-110.

Relevant Education and Experience

Dean Setoguchi

Mr. Setoguchi is a CPA, CA and currently Senior Vice President, Liquids Business Unit of Keyera Corp., a TSX listed energy midstream businesses, since April 2014. Mr. Setoguchi was formerly Chief Financial Officer of privately-held Laricina Energy Ltd. from October 2012 to March 2014. Prior thereto, Mr. Setoguchi was Vice President and Chief Financial Officer of publicly-held Keyera Corp. from September 2008 to October 2012. In addition, he has over 20 years of experience in the junior oil and gas sector which includes having served as former Chief Financial Officer of Cordero Energy Inc. and Resolute Energy Inc. In these roles, Mr. Setoguchi has acquired significant experience and exposure to accounting and financial reporting issues.

Mr. Setoguchi received his Bachelor of Management degree from the University of Lethbridge and received his Chartered Accountant designation from the Institute of Chartered Accountants of Alberta in September 1993.

David R. MacKenzie

Mr. MacKenzie is a professional engineer and independent businessman with over 35 years of oil and gas experience. Mr. MacKenzie is the long-time President of the Lincoln Group of Companies which has been making private equity investments in the oil and gas, technology and real estate industries since 1990. While leading the Lincoln Group of Companies, Mr. MacKenzie has occasionally served as a director and/or executive officer of certain companies in which the Lincoln Group has invested in including having served as President of Avant Garde Energy Corp. from September 2009 until its acquisition by Tamarack in June 2010. Mr. MacKenzie has also served on the boards of directors of numerous publicly-held companies such as TUSK Energy Company from January 2007 to April 2009, Zenas Energy Corp. from August 2005 to December 2006, and Blizzard Energy Inc. from December 2003 to July 2005, including having served on the audit committees of these three companies. In these roles, Mr. MacKenzie has acquired experience and exposure to accounting and financial reporting issues, as well as capital markets procedures, policies and rules.

Mr. MacKenzie received his Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and his Bachelor of Arts degree in Economics from Whitman College, Washington, USA.

John Leach

Mr. Leach is a CPA, CA and currently serves as Senior Vice President and Chief Financial Officer of Crew Energy Inc., a TSX listed, oil and gas producer since its spin-out from Baytex Energy in 2003. Mr. Leach was formerly a founding member of Baytex Energy Ltd. since 1993, serving in the finance department in increasing roles of responsibility culminating as its Vice President, Finance from 1998 to 2003. Prior to Baytex, Mr. Leach worked for KPMG, LLP. Through all of his roles, Mr. Leach has acquired significant experience and exposure to accounting and financial reporting issues as well as capital markets procedures, policies and rules.

Mr. Leach has been a Chartered Accountant since 1991, after graduating from the University of Saskatchewan with a Bachelor of Commerce degree.

Jeffrey Boyce

Mr. Boyce is a senior oil and gas executive with over 37 years of domestic and international experience in building, financing and managing public oil and gas companies. He is currently President of Evsam Holdings Ltd., a privately held investment company. Previously, he served as Executive Chairman and Director of PetroAmerica Oil Corp. prior to its acquisition in 2016, and was a co-founder, Senior Executive and Director of Sure Energy Inc., Clear Energy Inc. and Vermilion Resources Ltd. His background in oil and gas affords expertise across numerous areas, including financial markets, business development and exploration and land strategies, as well as corporate planning and negotiations. Throughout his career, he has served as a director and chairman or CEO of multiple oil and gas companies of varying sizes and has transacted on numerous acquisitions, dispositions or financings. Mr. Boyce obtained an Education Diploma in Business from Durham College in 1980 and received his Professional Landman Accreditation (P. Land) in 1992.

Audit Committee Oversight

Since January 1, 2014, Tamarack's board of directors has adopted all recommendations of the Audit Committee to nominate or compensate an external auditor.

Reliance on Certain Exemptions

Since January 1, 2013, the Company has not relied on the exemptions contained in Section 2.4 or Part 8 of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit Committee must approve all engagements for non-audit services which are expected to exceed $50,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than $50,000 the engagement may commence upon approval by the Chairman of the Audit Committee with all members being informed of the service at the next meeting of the Committee. All recommendations for services will be submitted by the Vice-President, Finance and Chief Financial Officer.

External Auditor Service Fees (by Category)

Audit Fees

KPMG LLP has served as Tamarack's external auditors since Tamarack's formation in 2002. The following table lists the fees paid or payable to KPMG LLP, by category, for the last two fiscal years:

Year Ended December 31	2017	2016
Audit fees1	277,000	438,000
Audit-related fees2	15,000	70,000
Tax fees3	0	-
All other fees4	-	-
Total fees	$292,000	$508,000

Notes:

(1) Audit fees consist of the aggregate fees billed for the audit or review of the Company's annual and quarterly financial statements that are normally provided in connection with statutory and regulatory filings or engagements.
(2) Audit-related fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as Audit fees. The services in this category include costs related to French translation.
(3) For tax compliance, tax advice and tax planning.
(4) For products and services other than the audit fees, audit-related fees and tax fees described above.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. Controls relating to land tenure, royalties and taxes, exploration, development, production, refining, transportation and marketing, among other things, are imposed by legislation and regulation enacted by both the federal and provincial levels of government all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas corporations of similar size. All current legislation is a matter of public record and Tamarack 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 Western Canada.

Pricing and Marketing of Oil and Natural Gas

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which means that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms. While exporters are free to negotiate prices and other terms with purchasers, crude oil exported from Canada is subject to regulation by the National Energy Board ("**NEB**"). Crude oil must be exported pursuant to either an export order or an export licence from the NEB. Crude oil exports for a term less than one year for light and medium crude, or two years for heavy crude, may be made pursuant to an export order. Any oil export for a longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB, which requires the approval of the Governor in Council (i.e. federal cabinet).

The price of natural gas is also determined by negotiation between buyers and sellers and natural gas exported from Canada is also subject to regulation by the NEB and the Government of Canada. While exporters are free to negotiate prices and other terms with purchasers, natural gas must be exported pursuant to either an export order or an export licence from the NEB. Natural gas exports (other than propane, butane and ethane) for a term of less than two years, or for a term of two to 20 years in quantities of not more than 30,000 m^3/day, may be made pursuant to an NEB export order. Exporters are required to obtain an export license from the NEB for natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas. The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

During 2017, the Company realized an average price of $59.42/bbl on sales of light crude oil and $46.01/bbl on sales of heavy crude oil, reflecting increases of 18% and 30%, respectively, over the average prices of $50.53/bbl and $35.45/bbl realized during 2016. These increases are consistent with period-over-period increases of 20% in the Edmonton Par average price for light oil and 29% for the Hardisty Heavy benchmark price for heavy oil. In comparison, during the same period, the US dollar-denominated average West Texas Intermediate price increased by approximately 18%.

The Company realized an average price on sales of natural gas of $2.32/Mcf in 2017, a 4% decline from the average price of $2.41/Mcf realized in 2016. The realized price of natural gas in 2017 reflected continued strong U.S. domestic natural gas production relative to demand resulting in high natural gas inventory levels, placing additional pressure on Canadian natural gas prices. North American supply and demand imbalances worsened through the second half of 2017. The discounts placed on Canadian natural gas production increased in 2017 compared to 2016 due to the lack of pipeline capacity out of Canada.

Pipeline Capacity

Despite the pipeline expansions over the past several years, there appears to be insufficient pipeline capacity to accommodate current production levels of oil and natural gas in Western Canada. Pipeline capacity may limit the ability to produce and market such production, and therefore western Canadian production may receive discounted pricing. Current pipeline construction projects before various regulatory bodies, if approved, are expected to alleviate this risk.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. NAFTA parties are generally prohibited from imposing minimum or maximum import and export price restrictions. However, import price restrictions are allowed to the extent that such restrictions are allowed by the anti-dumping and anti-subsidy provisions of the *General Agreement on Tariffs and Trade*.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian oil and natural gas exports. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain. Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. As of the date hereof, renegotiation discussions continue and the outcome of such negotiations remains unclear. As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry, including our business.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern 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 negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date 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 have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to reduce the benefits under such programs and to allow them to expire without renewal, and consequently few such programs are currently operative.

The Canadian federal government has signaled that it will inter alia phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration and implementing stringent reviews for pipelines. Additionally, in December 2016, the federal government issued the Pan-Canadian Framework on Clean Growth and 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 for wells drilled after this date. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. On July 12, 2016, the Government of Alberta announced that producers could apply for early adoption of the MRF in respect of wells spud between July 13, 2016 and December 31, 2016.

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

Producers pay a flat royalty rate of 5 percent of gross revenue from each well that is subject to the MRF until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the drilling and completion cost allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the MRF varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the MRF uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the drilling and completion cost allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Similarly, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane.

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

A number of incentive programs were created under the Old Framework, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program ("**EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the "**IETP**"). The Deep Oil Exploratory Well Regulation provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres. The EOR Program was replaced on January 1, 2017 by a new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**").

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened after May 1, 2010, with producing intervals that are deeper than 2,000 metres. The IETP provides royalty reductions to successful applicants making investments in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The AER determines which projects qualify for the IETP, as well as the level of support that will be provided. The IETP will expire on October 31, 2017.

Two strategic programs have been recently introduced under the MRF with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by water flooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of five per cent on crude oil, natural gas and NGL produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the MRF.

The new Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of five per cent until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard drilling and completion cost allowance under the MRF in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the MRF.

Saskatchewan

In Saskatchewan, the Crown owns approximately 70% of the oil and gas rights. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations. With respect to production obtained from Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as either "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as either "fourth tier oil", "third tier oil", "new oil", or "old oil". Depending on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Economy ("**SME**"), the royalty reserved to the Crown ranges from 0% to 45%.

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being gas produced from gas wells and the latter being gas produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as either "fourth tier gas", "third tier gas", "new gas", or "old gas". Depending on the categorization and classification of the natural gas, monthly production, and a reference price, the royalty reserved to the Crown ranges from 0% to 45%. As an incentive for the production and marketing of natural gas which may otherwise have been flared, the royalty rate on associated gas is less than on non-associated natural gas. Approximately one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the Crown. With respect to production from freehold lands, the tax levied on oil and gas production in the Province of Saskatchewan will depend on the classification of the oil or gas and the relevant Crown royalty rate.

On October 1, 2002, a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from qualifying oil wells and gas wells in the Province of Saskatchewan with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. In addition, oil produced from Enhanced Oil Recovery ("**EOR**") projects that commenced operation prior to April 1, 2005 are subject to a cost sensitive royalty regime determined by prescribed formulas which include a number of variables and which differentiate between pre and post project payout. EOR projects that commenced operation on or after April 1, 2005 are also subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenues prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout.

The SME updated three drilling incentives for wells drilled on or after October 1, 2002: the vertical well drilling incentive ("**VWD**"), the horizontal well drilling incentive ("**HWD**") and the exploratory gas well drilling incentive ("**EGWD**"). The VWD provides a royalty reduction to 2.5% and a freehold production tax rate of 0% for fixed volumes drilled from exploratory vertical oil wells and deep development vertical oil wells. Exploratory vertical oil wells are wells that meet certain prescribed criteria showing the well produces oil from an area which has not generally seen production. The incentive for exploratory vertical oil wells applies to the produced volume up to 16,000 m^3, depending on depth. Deep development vertical oil wells are deep or deepened wells, that are not exploratory oil wells, drilled to certain prescribed zones. The incentive for these wells applies to the produced volume up to 8,000 m^3. The HWD is very similar to the VWD, but applies to non-exploratory horizontal wells drilled on or after October 1, 2002 and provides the incentive to produced volumes up to 16,000 m^3, depending on depth. Finally, the EGWD provides a royalty reduction of the lesser of the fourth tier gas royalty rate (between 0%-5%) or 2.5% and a 0% freehold production tax rate. The incentive applies to wells that meet certain prescribed criteria showing the well produces gas from an area which has not generally been produced from. The incentive applies to the produced volume up to 25,000,000 m^3.

Land Tenure

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

The provinces of Alberta and Saskatchewan have 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. In Alberta, the NRF includes a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

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 operation 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, Tamarack 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 restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection 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 licences and authorizations, civil liability 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 greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The Canadian Environmental Protection Act, 1999 and the Canadian Environmental Assessment Act, 2012 provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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 to review federal environmental assessment processes 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. 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.

On November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast.

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

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

Alberta

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 will be 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.

To date, there are two regional plans that have been approved in Alberta: the Lower Athabasca Regional Plan ("**LARP**") and the South Saskatchewan Regional Plan ("**SSRP**"). The LARP covers the northeast corner of Alberta and the entirety of the Athabasca oil sands region. The SSRP covers the southernmost portion of the province. Both plans require a cumulative effects management approach which involves managing air, water and biodiversity through management frameworks that set environmental limits and triggers. Each plan also establishes several new conservation areas where new resource developments will generally be prohibited.

Saskatchewan

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

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 AER 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.

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 liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback fact or more sensitive to asset value fluctuations.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold AER Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances.
2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

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 an 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:

1. The licensee already has an LMR of 2.0 or higher;
2. The acquisition will improve the licensee's LMR to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an 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.

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

Saskatchewan

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

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, outlined below, impose certain costs and risks on the industry.

Federal

The federal government has contemplated various climate change strategies in recent years to reduce greenhouse gas ("**GHG**") emissions, ranging from a cap-and-trade regime to intensity based reduction targets.

To date, the Government of Canada has pursued a sector-by-sector regulatory approach, focusing first on the transportation and coal-fired electricity sectors. The government has imposed fuel efficiency standards for light duty vehicles and has passed regulations for coal-fired electricity generation facilities which will apply a stringent performance standard to new coal-fired electricity generation units and those coal-fired units that have reached the end of their economic life.

As 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), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; 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 Government of Canada 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 Government of Canada 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 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 Government of Canada 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.

The federal government is committing to reduce methane emissions from the oil and gas sector by 40 to 45 percent below 2012 levels by 2025. To implement this commitment, the federal government is expected to introduce regulations to reduce methane emissions from the oil and gas sector to address venting and fugitive emissions. The Canadian requirements are expected to cover emissions from the same sources that are subject to current and proposed U.S. regulatory requirements and will also require reductions from some unique Canadian sources such as heavy crude oil.

These regulations are expected to apply to new and existing sources, with the first requirements expected to come into force as early as 2020, and the remaining requirements expected to come into force by 2023.

The regulations are expected to apply to oil and gas facilities that are responsible for the extraction, production and processing and transportation of crude oil and natural gas. Regulatory requirements are expected to be designed to cover specific methane emission sources in Canada while minimizing administrative burden and providing the flexibility needed for efficient and effective operations in Canadian circumstances. Covered sources are expected to include: venting from wells and batteries (including associated gas at oil facilities), storage tanks, pneumatic devices, well completions, compressors and fugitive equipment leaks.

Environment and Climate Change Canada is expected to negotiate equivalency agreements with interested provinces and territories to enable these jurisdictions to be front.

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

In general, there is some uncertainty with regard to the impacts 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 our 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 accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG intensity-based limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs 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 November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan (the “**CLP**”) which proposes to introduce a carbon tax on all emitters. The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The Climate Leadership Act came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with federal legislation. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The Carbon Competitiveness Incentives Regulation (the "**CCIR**"), which replaces the SGER, also came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal framework.

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

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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. This legislation is intended to encourage new carbon capture and storage projects in Alberta. Alberta has committed $1.24 billion over 15 years to fund two largescale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the **"MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits emissions offsets and payments into a technology fund to achieve compliance, similar to the Alberta climate change initiative. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions. The MRGGA will apply to all facilities emitting over 50,000 tonnes of CO_2 equivalents per year.

RISK FACTORS

The following are certain risk factors related to Tamarack, its business, and the ownership of the securities of Tamarack which investors should carefully consider. The following information is a summary only of certain risk factors, is not exhaustive and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF. If any event arising from the risk factors set forth below occurs, Tamarack's business, prospects, financial condition, results of operation or cash flows and in some cases, its reputation, could be materially adversely affected.

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, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, 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 obtain the necessary approvals to build pipelines and other facilities to provide the oil and gas industry in Western Canada better access to markets 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 Company's reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Company's cash flow which could result in a reduced capital expenditure budget. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. A prolonged period of adverse market conditions may impede the Company's ability to refinance its Credit Facility or arrange alternative financing when the Credit Facility becomes due or if the lending limits under the Credit Facility are reduced upon periodic review. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Tamarack's cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations.

Exploration, Development and Production Risks

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

Future oil and natural 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, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in 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 could have a material adverse effect on future results of operations, liquidity and financial condition.

As is standard industry practice, Tamarack is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount considered consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, Tamarack could incur significant costs.

Commodity Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of Tamarack's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Tamarack's reserves. Tamarack might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Tamarack's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of Tamarack. These factors include economic conditions in the United States, Canada and Europe, the actions of the OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Throughout the latter half of 2014, most of 2015 and through 2016, world oil prices were severely depressed. Any further decline or extended weakness in the price of oil and gas would have an adverse effect on Tamarack's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on Tamarack's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. See "*Weakness in the Oil and Gas Industry*".

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

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 Tamarack'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 Tamarack or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*". In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares.

Reliance on Operators, Management and Key Personnel

Successfully exploring for, developing and commercializing oil and gas interests depends on a number of factors, not the least of which is the technical skill of the personnel involved. Tamarack's success will be, in part, dependent on the performance of its key managers and consultants. Failure to retain the managers and consultants, or to attract or retain additional key personnel, with the necessary skills and experience could have a materially adverse impact upon Tamarack's growth and profitability. Tamarack does not carry key person insurance. In addition, Tamarack may not be the operator of certain oil and gas properties in which it acquires an interest. To the extent Tamarack is not the operator of its oil and gas properties, Tamarack will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

Credit Facility Arrangements

The amount authorized under the Credit Facility is dependent on the borrowing base determined by the lenders to Tamarack under the Credit Facility. The Company is required to comply with covenants under the Credit Facility, and is subject to certain financial ratio tests, which from time to time, either affect the availability, or price, of additional funding and in the event that the Company does not complete therewith, the Company's access to capital could be restricted or repayment could be required. The failure of the Company to comply with such covenants, which may be affected by events beyond the Company's control, could result in the default under the Credit Facility which could result in the Company being required to repay amounts owing thereunder. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing, the lenders to Tamarack under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default and cross-acceleration provisions. In addition, the Credit Facility may, from time to time, impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Company's borrowing base is determined and re-determined by the lenders to Tamarack under the Credit Facility based on the Company's reserves, commodity prices, applicable discount rate and other factors as determined by the Company's lenders. A material decline in commodity prices could reduce the Company's borrowing base, therefore reducing the funds available to the Company under the Credit Facility which could result in a portion, or all, of the Company's bank indebtedness needing to be repaid.

Borrowing

From time to time, Tamarack may acquire assets or the shares of other corporations or otherwise finance its ongoing operations using debt, which may increase Tamarack's debt levels above industry standards. Further, a significant decrease in crude oil and natural gas prices, hedging losses or lower than expected production from Tamarack's properties may cause the Company's debt-to-cash flow ratio to rise above its peer standards. The level of Tamarack's indebtedness or debt-to-cash flow ratio from time to time could impair Tamarack's ability to obtain additional financing in the future on a timely basis and could affect the market price of the Common Shares.

Substantial Capital Requirements

Tamarack anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;

- the Company's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and Tamarack's securities in particular.

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Tamarack may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on its business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, Tamarack may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, Tamarack may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Tamarack's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company'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 affected materially and adversely. In addition, the future development of Tamarack's properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing could be highly dilutive to existing shareholders. Failure to obtain any financing necessary for Tamarack's capital expenditure plans may result in a delay in development or production on the Company's properties.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and cash flows to be derived therefrom, including many factors beyond Tamarack's control. The information concerning reserves and associated cash flow set forth in this AIF 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. Tamarack'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.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Many of Tamarack's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Tamarack's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon Tamarack's reserves.

In accordance with applicable securities laws, GLJ has used forecast price and cost estimates based on averages from three different independent evaluators' price forecasts in calculating reserves quantities. See "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*". 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 GLJ Report and such variations could be material. The GLJ Report and Viking Acquisition Reserves Report are based in part on the assumed success of activities Tamarack intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Tamarack's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of so that Tamarack 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 Tamarack, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Hedging

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

Third-Party Credit Risk and Delays

Tamarack 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, suppliers and other parties. In the event such entities fail to meet their contractual obligations to Tamarack, such failures could have a material adverse effect on Tamarack and its funds 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 Tamarack's ongoing capital program, potentially delaying the program and the result of such program until Tamarack finds a suitable alternative partner.

In addition to the usual delays in payments by purchasers of oil and natural gas to Tamarack or to the operators, and the delays by operators in remitting payment to Tamarack, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of Tamarack in a given period and expose Tamarack to additional third party credit risks.

Variations in Foreign Exchange Rates and Interest Rates

Operating costs incurred by Tamarack are generally paid in Canadian dollars. 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 has been volatile and has also increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact Tamarack's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of Tamarack's reserves as determined by independent evaluators. To the extent that Tamarack engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Tamarack may contract.

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

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Tamarack will actively compete for capital, skilled personnel, access to rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which will have greater technical and financial resources than Tamarack.

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 U.S. 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 the North American Free Trade Agreement, 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. U.S. legislators are considering the adoption of a border adjustment tax which, if adopted, would reduce or eliminate the cost U.S. companies can deduct from revenues for importing goods, including the importation of oil and gas. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Tamarack.

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

Geopolitical Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Tamarack 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, North Africa 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 Tamarack's net production revenue. In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack which may have a material adverse effect on its business, financial condition, results of operations and prospects. Tamarack does not have insurance to protect against the risk of terrorism.

Waterflood

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

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other 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 us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If we implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, or we are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could be materially adversely affected.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulations pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or other penalties as well as the responsibility to remedy environmental problems caused by Tamarack's operations. See "*Industry Conditions — Environmental Regulation*". Should Tamarack be unable to fully fund the cost of remedying an environmental problem, Tamarack might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Tamarack to incur costs to remedy such discharge. Although Tamarack believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Tamarack's financial condition, results of operations or prospects. See "*Industry Conditions – Environmental Regulation*".

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder 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 in the ratio of Tamarack's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Company'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*".

Regulatory

Oil and gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government and may be amended from time to time. See "*Industry Conditions*". 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 Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Tamarack's operations may require licences from various governmental authorities. There can be no assurance that Tamarack will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects. It is not expected that any of these controls or regulations will affect the operations of Tamarack in a manner materially different from how they would affect other oil and natural gas companies of similar size.

Royalty Regimes

There can be no assurance that the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes 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 – Royalties and Incentives*".

Climate Change

The Company's exploration and production facilities and other operations and activities emit GHG's and require the Company to comply with Alberta's greenhouse gas emissions legislation contained in the Climate Change and Emissions Management Act and the Specified Gas Emitters Regulation. The Company may also be required to comply with the regulatory scheme for GHG emissions ultimately adopted by the federal government, which is currently adopting sector-by-sector regulations. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of GHG regulations, including increases to the compliance costs contained in the Specified Gas Emitters Regulation and Alberta's new initiative to reduce venting and fugitive methane emissions, could also have a material impact on the nature of oil and natural gas operations, including those of the Company.

As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada has committed to reduce GHG emissions by 30% below 2005 levels by 2030. The mechanisms that will be implemented to meet this target have not been finalized. The Government of Canada also announced it would implement a Canada wide price on carbon to further reduce its greenhouse gas emissions. In addition, on January 1, 2017, the Climate Leadership Act came into effect in the Province of Alberta introducing a carbon tax on almost all sources of greenhouse gas emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on Tamarack and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Investment Returns

Tamarack has not paid dividends nor made a distribution on any of its securities. Further, Tamarack may never achieve a level of profitability that would permit payment of dividends or making other forms of distributions to security holders. In any event, given the stage of the Tamarack's development, it will likely be a long period of time before Tamarack could be in a position to make dividends or distributions to its investors. The payment of any future dividends by Tamarack will be at the sole discretion of the Board of Directors. In this regard, Tamarack currently intends to retain earnings to finance the expansion of its business and does not anticipate paying dividends in the foreseeable future.

Availability of Equipment and Qualified Personnel and Related Costs

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Tamarack and may delay Tamarack's exploration and development activities. In addition, the costs of qualified personnel and equipment in the areas where Tamarack's assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment in such areas.

Management of Growth

Tamarack may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Tamarack 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 Tamarack to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licences and Leases

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

Income Taxes

Tamarack files all required income tax returns and believes that it is in full compliance with the provisions of the *Tax Act* 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 the Company, 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 affects the Company. Furthermore, tax authorities having jurisdiction over Tamarack may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Project Risks

The Corporation 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 overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations;

regulatory changes; availability and productivity of skilled labour; and regulation of the oil and natural gas industry by various levels of government and governmental agencies.

These factors could result in Tamarack being unable to execute projects on time, on budget, or at all and may be unable to effectively market its oil and natural gas products.

Conflicts of Interest

Certain directors of Tamarack are also directors or officers of corporations which are in competition to the interests of Tamarack. No assurances can be given that opportunities identified by such board members will be provided to Tamarack. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as applicable under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Seasonality and Climate

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Tamarack.

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. Tamarack cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Tamarack's business, financial condition, results of operations and cash flows.

Dilution

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

Aboriginal Claims

Aboriginal peoples have claimed Aboriginal and treaty rights to portions of Western Canada. Tamarack is not aware that any claims have been made in respect of Tamarack's assets; however, if a claim arose and was successful this could have an adverse effect on Tamarack and its operations.

Insurance

Tamarack's involvement in the exploration for and development of oil and gas properties may result in Tamarack becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Tamarack 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, Tamarack may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Tamarack. The occurrence of a significant event that Tamarack is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Tamarack's financial position, results of operations or prospects.

Litigation

In the normal course of Tamarack'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, relating to personal injuries, property damage, property taxes, 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 Tamarack and as a result, could have a material adverse effect on Tamarack's assets, liabilities, business, financial condition and results of operations. Even if Tamarack prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Pipeline Systems

The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results.

Information Technology Systems and Cyber-Security

Tamarack depends upon the availability, capacity, reliability and security of its information technology infrastructure to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts and communicate with employees and third-party partners. The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of Tamarack's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or competitive position. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as reputation. Tamarack applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Forward-Looking Information May Prove Inaccurate

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was a subject of, during the most recently completed financial year that were or are material to the Company, nor are any such legal proceedings known to the Company to be contemplated which could be deemed material to the Company.

To the knowledge of management of the Company, there have not been any penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the most recently completed financial year, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and the Company has not entered into any settlement agreement before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below, to the knowledge of the directors and officers of the Company, none of the directors or executive officers of the Company, nor any person or Company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any of their respective associates or affiliates, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the Company's current year or in any proposed transaction which has materially affected or is reasonably expected to materially affect the Company.

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

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, no material contracts were entered into by the Company during the most recently completed financial year nor are any material contracts in effect that were entered into prior to the beginning of the most recently completed financial year.

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the GLJ Report and Viking Acquisition Reserves Report prepared by GLJ, an independent reserves evaluator. As of March 8, 2018, to the knowledge of the Company, the directors, officers, employees and consultants of GLJ who participated in the preparation of the GLJ Report and Viking Acquisition Reserves Report who were in a position to directly influence the preparation or outcome of the preparation of the GLJ Report and Viking Acquisition Reserves Report, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares. In addition, none of the officers, directors, employees or consultants of GLJ are currently expected to be elected, appointed or employed as a director, officer or employee of the Company or any of the Company's associates or affiliates.

KPMG LLP, Chartered Professional Accountants, are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Other than as set out above, no other experts (whose profession or business gives authority to a report, valuation, statement or opinion made by them) were named in any securities disclosure document filed by the Company pursuant to NI 51-102 in the most recently completed financial year.

ADDITIONAL INFORMATION

Additional information regarding Tamarack may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the Company's management information circular dated May 18, 2017 relating to the annual meeting of shareholders held on June 22, 2017. Additional financial information is available in the annual audited financial statements of the Company and the related management's discussion and analysis for the financial year ended December 31, 2017.

DEFINITIONS

Throughout this AIF the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

"**Alberta 1767001**" means 1767001 Alberta Ltd., a former direct and wholly-owned subsidiary of the Company which amalgamated with Sure Energy on October 9, 2013 to form Sure Amalco;

"**ABCA**" means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

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

"**Amended Amalgamation Agreement**" means the amended and restated amalgamation agreement dated May 20, 2010 by and among the Company, PrivateCo and Subco;

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

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

"**Common Shares**" means common shares in the capital of Tamarack Valley Energy Ltd.;

"**Company**" or "**Tamarack**" means Tamarack Valley Energy Ltd., a corporation existing under the laws of the Province of Alberta;

"**Credit Facility**" means the credit facilities of the Company with a syndicate of Canadian chartered banks, consisting of an extendible revolving syndicated term credit facility in the amount of $270 million and an extendible revolving working capital credit facility in the amount of $20 million; next annual review before May 27, 2018;

"**Echoex**" means Echoex Ltd.;

"**Exchange Agreement**" means the exchange agreement dated May 20, 2010 between the Company, PrivateCo, Subco and certain holders of preferred shares in the capital of PrivateCo and entered into in connection with the Restructuring Transaction;

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

"**GLJ Report**" means the independent engineering report dated February 28, 2018 and evaluating the crude oil, natural gas and NGLs reserves of the Company effective as of December 31, 2017;

"**IFRS**" means International Financial Reporting Standards as issued by the International Accounting Standards Board;

"**July 2016 Financing**" means the $81.6 million gross bought deal financing under which the Company issued 20,110,050 2016 Subscription Receipts at $3.66 each, for gross proceeds of $73.6 million plus 1,952,000 Flow-Through Shares at $4.10 each, for gross proceeds of $8.0 million;

"**March 2016 Offering**" means the Company's bought deal offering of 14,966,100 Common Shares (including an over-allotment option of 1,952,100 Common Shares) at an issue price of $2.92 per Common Share, generating gross proceeds of $43.7 million;

"**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*;

"Penny Acquisition" means the strategic asset acquisition comprised of a light oil pool at Penny in Southern Alberta, which has only recovered 10% of estimated oil in place to date, has a decline rate of approximately 12-13%, has been under waterflood for over 15 years and which closed on July 12, 2016;

"Penny and Redwater Acquisitions" means the collective strategic asset acquisitions at Penny and Redwater, both of which closed in July, 2016;

"PrivateCo" means privately-held Tamarack Valley Energy Ltd.;

"**Pro-Forma Reserves Report**" means the combined reserves report reflecting the Modified Look-Ahead Summary and the Viking Acquisition Reserves Report, with an effective date of January 31, 2017;

"**Redwater Acquisition**" means the strategic asset acquisition comprised of assets in Redwater and Wilson Creek, Alberta, contiguous with Tamarack's existing Viking and Cardium interests with significant infrastructure, including an 82% ownership in a central oil battery at Redwater with capacity to handle 8,000 bbl/d of oil and 1.5 mmcf/d of natural gas, which closed on July 25, 2016;

"**Restructuring Transaction**" means the restructuring transaction completed on June 17, 2010 between the Company, PrivateCo and Subco pursuant to the terms of the Amended Amalgamation Agreement and included the election of a new Board of Directors, the appointment of a new management team and a change of name of the Company from "Tango Energy Inc." to "Tamarack Valley Energy Ltd.";

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval;

"**Spur**" means Spur Resources Ltd., the privately-held company acquired by Tamarack on January 11, 2017 pursuant to a plan of arrangement under the provisions of the *Business Corporations Act* (Alberta);

"**Subco**" means 1529232 Alberta Ltd., a former direct and wholly-owned subsidiary of the Company which amalgamated with PrivateCo pursuant to the terms of the Amended Amalgamation Agreement;

"**Sure Amalco**" means Sure Energy Inc., a corporation formed on the amalgamation of 1767001 and Sure Energy under the ABCA;

"**Sure Energy**" means Sure Energy Ltd.;

"**Sure Energy Acquisition**" means the acquisition by the Company of all of the issued and outstanding shares of Sure Energy pursuant to a plan of arrangement;

"**TAC**" means Tamarack Acquisition Corp., a wholly-owned subsidiary of the Company existing under the laws of Alberta;

"**TAC Preferred Shares**" means those preferred shares in TAC exchangeable for Common Shares pursuant to the terms and conditions of the Exchange Agreement;

"**TSX**" means the Toronto Stock Exchange;

"**TSX-V**" means the TSX Venture Exchange;

"**United States**" or "**U.S.**" means the United States of America and includes its territories and possessions.

"**Viking Acquisition**" means the 2017 transformative acquisition of Spur Resources Ltd.'s Viking oil assets in Saskatchewan and Alberta;

"**Viking Assets**" means the light-oil weighted, Viking-focused assets located across 300,000 net acres of high working interest acreage in the Consort and Esther areas of southeast Alberta and the Milton and Hoosier areas of southwest Saskatchewan, which were acquired through the Viking Acquisition;

"**Wilson Creek Cardium Acquisitions**" means collectively, the three separate 2015 acquisitions from three industry majors of Cardium interests contiguous with Tamarack's existing Cardium interest in Wilson Creek, Alberta.

"**2015 CDE Flow-Through Shares"** means 2,156,800 (including over-allotment) Common Shares of the Company issued on a "CDE Flow-Through" basis at a price of $4.15 per 2015 CDE Flow-Through Share.

"2015 Subscription Receipts" means the 2015 bought deal financing agreement consisting of 13,228,000 subscription receipts priced at $3.78 per subscription receipt for gross proceeds of approximately $50.0 million.

"2016 Subscription Receipts" means the 20,110,500 subscription receipts priced at $3.66 each, issued under the July 2016 Offering.

CONVENTIONS

Certain other terms used but not defined in this AIF are defined in NI 51-101 and, unless the context otherwise requires, have the same meanings as ascribed to them in NI 51-101. Unless otherwise indicated, references in this AIF to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

This annual information form contains certain oil and gas metrics, including finding and development costs, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	stock tank barrels

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM or Mm	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
API°	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
L	litre
m^3	cubic metres
Mcfe	means 1,000 cubic feet equivalent on the basis of one Bbl of crude oil for six Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
M$	thousands of dollars
Mm$	millions of dollars
USD	United States dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SELECTED 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	cubic meters	28.320
cubic meters	cubic feet	35.315
Bbls	cubic meters	0.159
cubic meters	Bbls	6.290
feet	metres	0.305
meters	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute forward-looking statements. These statements relate to future events or the Company's future plans or performance. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements or information is often, but not always, identified by the use of words such as "anticipate", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company's presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Tamarack bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions. Management believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements should not be unduly relied upon.

In particular, this AIF contains forward-looking statements pertaining to the following:

- business strategy, objectives, strength and focus;
- the performance characteristics of the Company's oil and natural gas properties, individually, including the assets acquired under the Sure Energy Acquisition, the Wilson Creek Cardium Acquisitions, the Redwater Acquisition, the Penny Acquisition and the Viking Acquisition;
- oil and natural gas production levels;
- expectations regarding the Company's growth and risk profile;
- the size of the Company's oil and natural gas reserves;
- projections of market prices and costs;
- supply of, and demand for, oil and natural gas;
- expected year end 2018 net debt to annualized adjusted funds flow (including hedges) ratio;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the ability of the Company to achieve drilling success consistent with management's expectations;

- drilling plans, expectations and timing of drilling;
- the Company's ability to attract and retain qualified personnel;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- treatment under governmental regulatory regimes and tax laws;
- expected effect of regulatory regimes and controls;
- tax horizon and future income taxes;
- use of Credit Facility funds;
- the Company's capital program and guidance for 2018;
- expected source of funds in connection with the Company's capital program;
- expectations regarding commodity prices in 2018;
- deployment of the Company's 2018 capital program;
- expectations regarding dividends;
- the expected allocation of the Company's 2018 capital expenditure budget;
- the source of funds for the Company's 2018 expenditure budget;
- the value of the capital expenditures to be made by the Company during the first and second halves of 2018;
- capital expenditure programs and the timing and method of financing thereof; and
- abandonment and reclamation costs.

Statements relating to "reserves" are deemed to be 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. See "*Statement of Reserves Data and Other Oil and Gas Information*".

The forward-looking information and statements contained in this AIF reflect management's current views and are based on certain assumptions, including assumptions as to future economic conditions and courses of action, as well as other factors that management believes are appropriate in the circumstances. Such forward-looking statements are subject to risks and uncertainties and no assurance can be made that any of the events anticipated by such statements will occur or, if they do occur, what benefit the Company will derive from them. The Company has made assumptions regarding, among other things:

- the ability of the Company to achieve drilling success consistent with management's expectations;
- the ability of the Company to secure equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the timing and cost of pipeline and facility construction and expansion and the ability of the Company to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to market its oil and natural gas and to transport its oil and natural gas to market;
- the ability of the Company to obtain capital to finance its exploration, development and operations; and
- future oil and natural gas prices.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- volatility in market prices for oil and natural gas;
- lack of transportation and inability to produce oil and natural gas reserves and resources;
- adverse regulatory rulings, orders and decisions;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling and processing problems and other problems in producing reserves and resources;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- stock market volatility and market valuations;
- the impact of climate change and climate change regulations;
- possible renegotiation of international trade agreements including NAFTA;
- the risks of the oil and gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- the failure to obtain industry partner and other third party consents and approvals, as and when required;
- the availability of capital on acceptable terms;
- actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- changes in income tax laws or changes in tax laws or trade laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

These factors should not be considered as exhaustive. The reader is cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved will vary from the information provided herein and the variations may be material. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there are no representations by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this AIF are made as of the date hereof, and the Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

OIL AND GAS MEASURES

This AIF discloses Viking Areas drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved locations and probable locations derived from an internal evaluation using standard practices as prescribed in the Canadian Oil and Gas Evaluations Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 733 (6689.6 net) Viking Areas drilling locations identified herein, 161 (149.5 net) are proved locations, 126 (116.1 net) are probable locations and 446 (424.0 net) are unbooked locations. Unbooked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

NON-IFRS MEASURES

This document contains the terms “funds from operations”, adjusted funds flow”, “net debt”, “netbacks” and “capital cost payout”, which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses funds from operations and adjusted funds flow as key measures to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (bank debt plus working capital deficiency and excluding fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers corporate netbacks a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and production and transportation costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts. The Company also considers capital cost payout a key measure as it demonstrates the financial status of the Company’s projects.

(a) Funds from Operations and Adjusted Funds Flow - Tamarack’s method of calculating funds from operations and adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Tamarack calculates funds from operations as cash provided operating activities, as determined under IFRS, before the changes in non-cash working capital related to operating activities and before transaction costs related to acquisitions or dispositions that are not part of regular ongoing operations. Adjusted funds flow represents funds from operations before abandonment expenditures. The Company believes the uncertainty surrounding the timing of collection, payment or incurrence of these items makes them less useful in evaluating Tamarack’s operating performance. Tamarack uses funds from operations and adjusted funds flow as a key measure to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment.

(b) Operating Netback - Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and production and transportation costs calculated on a per boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company’s netbacks can be seen on page 7 in the section titled “Operating Netback”.

(c) Net Debt - Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Management considers net debt an important measure to assist in providing a more complete understanding of cash liabilities.

(d) Capital Cost Payout - Management uses certain industry benchmarks, such as capital cost payout, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Capital cost payout is achieved when revenues, less royalties, production and transportation costs are equal to the total capital costs associated with drilling, completing, equipping and tying in a well. Management considers capital cost payout an important measure to evaluate its operational performance, as it demonstrates the economic status of the Company's projects, and allows the Company to understand how quickly capital can be returned from drilling a well, which helps assess the Company's ability to generate value.

APPENDIX "A"

Form 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Tamarack Valley Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Valuation	Location of Reserves (Country)	NPV10 Audited ($000)	NPV10 Evaluated ($000)	NPV10 Reviewed ($000)	NPV10 Total ($000)
GLJ Petroleum Consultants Ltd.	Dec 31/17	Canada	-	1,178,587	-	**1,178,587**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 28, 2018.

"Originally Signed by"

Tim Freeborn, P. Eng.
Vice President

APPENDIX "B"

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

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

An independent qualified reserves evaluator has evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

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, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; 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) "*Brian L. Schmidt*"

Brian L. Schmidt, President & CEO

(signed) "*Dave Christensen*"

Dave Christensen, Vice President, Engineering

(signed) "*Ian Currie*"

Ian Currie, Director

(signed) "*David MacKenzie*"

David MacKenzie, Director

(signed) "*Jeff Boyce*"

Jeff Boyce, Director

March 8, 2018

APPENDIX "C"

AUDIT COMMITTEE MANDATE

Policy Statement

Tamarack Valley Energy Ltd. (the "**Corporation**") has established and maintains an Audit Committee, (the "**Committee**") to assist the Board of Directors (the "**Board**") in carrying out its oversight responsibility with respect to public reporting related to the Corporation's internal controls, financial reporting and risk management processes. The Committee will be provided with resources commensurate with the duties and responsibilities set out herein and assigned to it by the Board from time to time, including administrative support. If determined necessary by the Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition

1. The Committee shall consist of at least three directors. The Board shall appoint the members of the Committee. The Board shall appoint one member of the Committee to be the chairman of the Committee (the "**Chairman**").
2. Each director appointed to the committee by the Board shall be "independent" as required under the applicable securities laws and the applicable rules of any stock exchange on which the securities of the Corporation are listed unless a member is deemed not to be independent only by virtue of being an executive officer of a subsidiary entity.
3. Each member of the Committee shall be "financially literate" as required under the applicable securities laws, including without limitation National Instrument 52-110 - Audit Committees ("**NI 52-110**"). In order to be financially literate, a director must have 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 complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements. If available, at least one member shall have "accounting or related financial management expertise", meaning the ability to analyze and interpret a full set of financial statements, including the notes attached thereto, in accordance with Canadian generally accepted accounting principles.
4. A director appointed by the Board to the Committee shall be a member of the Committee until replaced by the Board or until his or her resignation.

Meetings and Operations

1. The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chairman and whenever a meeting is requested by the Board, a member of the Committee, the external auditors (the "**auditors**"), or an officer of the Corporation. Meetings of the Committee shall correspond with the review of the quarterly and annual financial statements and the associated management's discussion and analysis ("**MD&A**").
2. Notice of each meeting of the Committee shall be given to each member of the Committee and to the auditors, who shall be entitled to attend each meeting of the Committee and who shall attend whenever requested to do so by a member of the Committee.
3. A quorum for the transaction of business at a meeting of the Committee shall consist of two members of the Committee.
4. A member or members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.
5. In the absence of the Chairman, the members of the Committee shall choose one of the members present to be chairman of the meeting. In addition, the members of the Committee shall choose one of the persons present to be the secretary of the meeting.
6. The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer and other members of senior management shall be invited to attend meetings of the Committee upon the request of the Committee; subject, however, to the requirement that the Committee (i) hold in camera sessions of the members of the Committee, without management representatives present at every meeting of the Committee, and (ii) meet with the auditors separately and independent of management at every meeting at which the auditors are in attendance.

7. Minutes shall be kept of all meetings of the Committee.

Authority and Reporting

1. In discharging its duties and responsibilities, the Committee shall have the authority to:
   (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;
   (b) discuss with the management of the Corporation, its subsidiaries and affiliates and staff of the Corporation, any affected party, contractors and consultants of the Corporation and the auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate;
   (c) engage independent counsel and other advisors (including a second firm of external auditors) as it determines necessary to carry out its duties; and
   (d) set and pay the compensation for any advisors employed by the Committee.
2. The Committee shall after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

Primary Duties and Responsibilities

1. The Committee's primary duties and responsibilities regarding its audit function are to:
   (a) review with the external auditors the audit function generally, the objectives, staffing, locations, co-ordination, and scope of proposed audits of the financial statements of the Corporation;
   (b) review with management and the external auditors, and recommend to the Board for approval and release to shareholders, the quarterly and annual financial statements of the Corporation, together with related reports to shareholders, MD&A associated with such financial statements and, delegated by the board, other public filings (such as prospectus or annual information forms) containing financial disclosures;
   (c) review with the auditors and management, and monitor the management of, the principal risks that could affect the financial reporting of the Corporation;
   (d) review and assess the framework of and periodically consider the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance through discussions with management and the auditor;
   (e) consider the independence and performance of the Corporation's auditors;
   (f) deal directly with the auditors to approve the annual external audit plan, other services (if any) and associated fees;
   (g) approve the audit engagement and consider the external audit process and results;
   (h) provide an avenue of communication among the auditors (both external and internal, if any), management and the Board, and direct the external auditors to report directly to the Committee; and
   (i) establish and monitor procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other "whistleblower" issues, and review the minutes of any Committee meetings held in connection with any subsidiary companies of the Corporation.
2. The Committee shall, in connection with the financial aspects of the Corporation's business:
   (a) review the annual external audit plan with the Corporation's auditors and with management and approve the engagement letter relating thereto;
   (b) discuss with management and the auditors any proposed changes in major accounting policies or principles, the presentation and effect of significant risks and uncertainties and key estimates and judgements of management that may be material to financial reporting;
   (c) review with management and with the auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;

(d) review any problems experienced or concerns expressed by the auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;

(e) review with management the process of identifying, monitoring and reporting the Corporation's risk management policies and procedures and the principal risks affecting financial reporting;

(f) review and evaluate any recommendations of the auditors and decide the appropriate course of action;

(g) consider consistency of the data reported in the financial statements, annual and quarterly reports and related public disclosure documents;

(h) review audited annual financial statements and related documents in conjunction with the report of the auditors and significant variances between comparative reporting periods as set out in the MD&A;

(i) review, independently of management, and without management present, the results of the annual external audit, the audit report thereon and the auditor's review of the related MD&A, and discuss with the auditor the quality of accounting principles used, any alternative treatments of financial information that have been discussed with management, the ramifications of their use and the auditor's preferred treatment and any other material communication with management;

(j) consider and review with management:

  (i) all unadjusted errors identified by the external auditors,

  (ii) the internal control memorandum or management letter containing the recommendations of the auditors and management's response, if any, including any evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weakness;

(k) review with management and the auditors the quarterly unaudited financial statements and MD&A before release to the public;

(l) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectus, annual reports, annual information forms, MD&A and press releases;

(m) review and approve the Corporation's hiring policies regarding employees and former employees of the present and former auditors;

(n) review with management the Corporation's relationship with regulators and the timelines and accuracy of the Corporation's filings with regulatory agencies; and

(o) review with management all related party transactions and the development of policies and procedures related to those transactions.

Auditors

1. The Committee shall:

  (a) consider the independence and performance of the auditors and annually recommend to the Board the appointment or discharge of the auditor when circumstances are warranted and recommend to the Board the compensation of the auditors;

  (b) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the auditors, or the auditors of any of the Corporation's subsidiary entities;

  (c) when there is to be a change of auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and related documentation required pursuant to National Instrument 51-102 - Continuous Disclosure Obligations, with respect to a change of auditors (or any successor legislation) and the planned steps for an orderly transition period;

  (d) review all material written communications between the auditor and management; and

(e) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of auditors.

Financing Matters

1. The Committee shall:

   (a) review all securities offering documents (including documents incorporated therein by reference) of the Corporation;

   (b) review findings, if any, from examinations or reviews performed by regulatory agencies with respect to financial matters;

   (c) review management's consideration of the Corporation's compliance with laws and regulations;

   (d) review management's assessment of current and expected future compliance with covenants under any financing agreements;

   (e) if requested by the Board, review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases, as well as any related securities filings;

   (f) if requested by the Board, review the proposed repurchase of public and private debt, equity and hybrid securities; and

   (g) in consultation with management understand the Corporation's capital structure and financial risks arising from exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit and review the management of these risks including any proposed hedging of the exposures, including receiving a summary report of the hedging activities and hedge-related instruments.

Other

1. The Committee shall consider the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.
2. The Committee shall consider the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.
3. The Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Committee by any member of the Board, a shareholder of the Corporation, the auditors, or management.
4. The Committee shall review, on an annual basis this mandate and recommend any changes to the Board.
5. The Committee will perform any other activities consistent with this mandate, the Corporation's bylaws and applicable laws as the Committee or the Board deems necessary or appropriate.

Scope and Reliance

1. While the Committee has the responsibilities, duties and authorities herein, it is not required to plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the auditors. The Committee, its Chairman and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Committee to provide broad oversight to the financial disclosure, financial risk and control related activities of the Corporation, and are specifically not accountable nor responsible for the day-to-day operation of such activities. Although designation of a member or members as being "financially literate" or a "financial expert" is based on each such individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Committee, designation as being "financially literate" or a "financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Committee and Board in the absence of such designation. Rather, the role of any financially literate individual or financial expert, like the role of all Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Corporation's; financial information or public disclosure.
2. Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Corporation from which

it receives information, (ii) the accuracy of the information provided to the Committee by such persons or organizations, and (iii) representations made by management of the Corporation, the external auditors of the Corporation, independent counsel, and other advisors and experts to the Corporation and its subsidiaries.

Pre-Approval Policies and Procedures

1. The Audit Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit Committee must approve all engagements for non-audit services which are expected to exceed $50,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than $50,000 the engagement may commence upon approval by the Chairman of the Audit Committee with all members being informed of the service at the next meeting of the Committee. All recommendations for services will be submitted by the Vice-President, Finance and Chief Financial Officer.