tamarack valley ENERGY ltd.

Annual Information Form

For the Year Ended December 31, 2015

March 24, 2016

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The information in this Annual Information Form is given as of December 31, 2015 unless otherwise indicated.

TAMARACK VALLEY ENERGY LTD.

BACKGROUND

Tamarack Valley Energy, Ltd ("**Tamarack**" or the "**Company**") is a junior, high growth oil and natural gas company engaged and focused on the exploration, development, production and acquisition of petroleum and natural gas properties within Western Canada.

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.

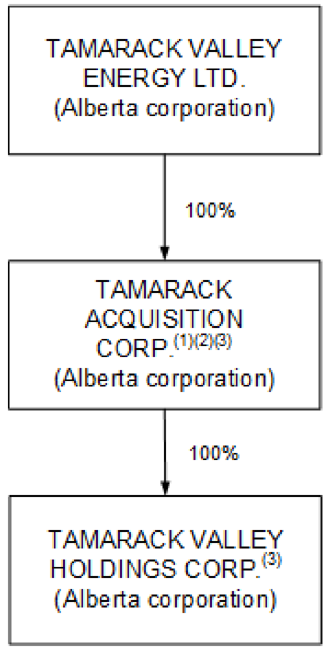
Tamarack is a "reporting issuer" or the equivalent in each of the Provinces of Canada. The Common Shares began trading on the TSX on August 24, 2015. Previously, the Common Shares were trading on the TSX-V. The Common Shares trade under the symbol "TVE".

The Company's head office is located at Suite 3100, 250 – 6th Avenue S.W., Calgary, Alberta, T2P 3H7. The registered office of the Company is located at Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1.

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, 2015.**(4)** The below diagram does not include all of the subsidiaries of Tamarack. The total assets of the excluded subsidiaries do not exceed 10% of the consolidated assets 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 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 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, the only material subsidiary of Tamarack is 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 24, 2016, Tamarack announced record fourth quarter 2015 production average of 9,968 boe/d (61% liquids), which is an increase of 14% from the third quarter of 2015 and is higher than exit production guidance of 9,500 to 9,700 boe/d (55-60% liquids). Tamarack achieved its exit production target while spending $107.4 million which was approximately 15% lower than guidance of $125 to 130 million in 2015. Year-end net debt of $97.9 million was approximately 17% lower than guidance of $125 to 130 million, and was attributable to improved capital efficiencies leading to strong production volumes with lower spending. 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 February 29, 2016, Tamarack announced that it had entered into a bought deal financing agreement to issue up to 14,966,100 Common Shares (including an over-allotment option of up to 1,952,100 Common Shares) at an issue price of $2.92 per Common Share, for gross proceeds of up to $43.7 million (the "**March 2016 Offering**"). Proceeds of the March 2016 Offering will be used to initially reduce bank indebtedness and for general corporate purposes. The March 2016 Offering closed on March 18, 2016.

On February 29, 2016, Tamarack re-affirmed its 2016 guidance and indicated that as a result of the March 2016 Offering, the estimated year-end 12-month trailing debt 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.

On February 24, 2016, the Company announced its 2015 year-end reserves report and provided an operations update. Tamarack realized reserves and production growth through 2015, while reducing net debt. In 2015, the Company drilled 15 (13.9 net) horizontal Cardium oil wells in the core Wilson Creek and Alder Flats areas and on June 15, 2015 closed a strategic acquisition of assets within these areas, further contributing to Tamarack's growth. The operational success realized in 2015 coupled with ongoing cost reduction initiatives ensure Tamarack is well positioned for continued measured growth and long-term sustainability. See "*Statement of Reserves and Other Oil and Gas Information*".

On February 24, 2016, Tamarack increased its 2016 guidance range to account for lower commodity prices. The updated guidance accounted for a 2016 WTI average of $33.00/bbl USD and an AECO average of $2.00/GJ with a plan to adjust capital spending as commodity prices change. The updated guidance ranges included: (i) capital expenditures of $40 to $57 million (which includes expected capital costs associated with fulfilling the remainder of Tamarack's 2016 farm-in commitments of approximately $7 million for drilling approximately 3 net wells); (ii) average production of 8,700 to 9,700 boe/d (approximately 51 to 57% oil and NGLs); (iii) exit production of 8,600 to 9,800 boe/d (approximately 50 to 55% oil and NGLs); (iv) estimated year-end 12-month trailing debt cash flow (including hedges) ratio between 1.6 and 2.3 times; and (v) at least $50 million of liquidity under the Credit Facility, which remained unchanged from the original guidance. Tamarack also indicated it would continue to closely monitor the broader commodity price environment and has the flexibility to further reduce capital expenditures by an additional $12 to $17 million from original levels, if commodity prices would not improve from current levels.

On January 19, 2016, Tamarack released its 2016 capital program and guidance, which was designed with the priority of protecting its balance sheet. Under the 2016 capital program, capital will initially be allocated to satisfying drilling commitments and to the extent proceeds remain after satisfying such drilling commitments, capital will be allocated to pursue possible acquisition opportunities and other general drilling. An estimated 75% to 80% of Tamarack's 2016 capital expenditures will be in the Wilson Creek and Alder Flats areas, as the majority of Tamarack's drilling commitments and possible acquisition opportunities fall within these areas. As at December 31, 2015, Tamarack had drilled approximately 12 net wells pursuant to its farm-in commitment, leaving approximately 3 additional net wells to be drilled by December 31, 2016. If the Company receives access by December 31, 2016 to lands which are currently subject to surface access restrictions, then 5 additional net wells will be required to be drilled by December 31, 2017. The expected capital costs associated with fulfilling the remainder of Tamarack's farm-in commitments are approximately $7 million to $20 million depending on the number of commitment wells required to be drilled.

The 2016 capital program and guidance was based on a 2016 WTI average of $40.00/bbl USD and an AECO average of $2.45/GJ with a plan to adjust capital spending as commodity prices change. Despite having high quality drilling inventory that achieves 1.5 year payout or less at current strip prices, the Company has begun to adjust capital spending as a result of the recent drop in commodity prices. The Company's top priority is to maintain a strong balance sheet in order to continue to pursue tuck-in acquisitions within its core areas and to continue to add to the Company's drilling inventory. This includes deferring approximately $6 to $8 million of capital into the second half of 2016. In Tamarack's initial 2016 capital program and guidance, Tamarack had indicated it would continue to closely monitor the broader commodity price environment and has the flexibility to further reduce capital expenditures by an additional $12 to $17 million from original levels, if commodity prices would not improve from current levels.

On January 19, 2016, Tamarack announced that the lenders under its Credit Facility had completed their mid-year lending value review during the third quarter of 2015 and that the lenders agreed to maintain its Credit Facility at $165 million. The $165 million Credit Facility is comprised of a $155 million revolving credit facility and a $10 million operating facility. The next scheduled review of the Credit Facility is currently underway and expected to conclude by May 27, 2016. As the available lending limits of the Credit Facility are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review.

Developments in 2015

On January 28, 2015, Tamarack announced that its Board of Directors approved a $47 million 2015 capital expenditure budget, with $10.5 million expected to be invested in the first half of the year.

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 ("**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 ("**CDE Flow-Through Shares**") at a price of $4.15 per CDE Flow-Through Share for gross proceeds of approximately $5.0 million. The net proceeds of the 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 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 Subscription Receipts, 4,564,350 Common Shares and 2,186,800 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. The next scheduled mid-year review was to be completed by November 30, 2015. In addition, the Company reduced its 2015 capital expenditures budget to $125 to $130 million from $130 to $140 million.

On August 24, 2015, Tamarack graduated to the Toronto Stock Exchange 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 are independent directors. Additionally, effective December 17, 2015, Rummy Basra was appointed as Corporate Secretary of the Company.

Developments in 2014

On January 28, 2014, Tamarack announced that it had entered into a bought deal financing agreement to issue 7,000,000 Common Shares at an issue price of $4.30 per Common Share, for gross proceeds of $30.1 million (the "**February 2014 Offering**"). On January 29, 2014, the Company announced an increase in the size of the February 2014 Offering to 14,000,000 Common Shares for total gross proceeds of $60.2 million. Proceeds of the February 2014 Offering were used to reduce bank indebtedness, partially fund the Company's continuing capital program and for general corporate purposes. The February 2014 Offering closed on February 19, 2014. Concurrent with the February 2014 Offering, the Board of Directors approved an increase to the 2014 capital budget to $90-92 million from $68 million.

On March 7, 2014, the Company increased its credit facilities by increasing the revolving operating demand line of credit from $85 million to $90 million. The Company's non-revolving acquisition/development demand line of credit remained at $18 million. These facilities were secured by an aggregate of $155 million in debentures with a floating charge over all the assets of Tamarack.

On April 10, 2014 the Company's Board of Directors announced the resignation of Mr. Sheldon Steeves from the Board to pursue other business interests. Mr. Steeves served on the Board since the acquisition of Echoex on April 18, 2012.

On May 1, 2014 the Company announced the retirement of Mr. Niels Gundesen from the role of Vice President, Engineering and the concurrent promotion of Mr. Dave Christensen to the role. Mr. Christensen has more than 30 years of experience in the oil and gas industry, and joined Tamarack in February 2014**.**

On August 11, 2014 Tamarack announced that the Company had executed a new credit facility with a syndicate of Canadian chartered banks, consisting of a $100 million revolving credit facility and a $10 million operating facility, which collectively have a term of 364 days. The credit facility was subject to its next 364 day extension by May 30, 2015. If not extended, the credit facility would have ceased to revolve and all outstanding balances would become repayable in one year from that extension date. The interest rate on both the revolving facility and operating facility was determined through a pricing grid which was based on a net debt to cash flow ratio. The interest rate varied from a low of the bank's prime rate plus 1.0%, to a high of the bank's prime rate plus 2.5%. The standby fee for the credit facility varied based on a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the credit facilities. The credit facility was secured by a $300,000,000 supplemental debenture with a floating charge over all assets.

On September 30, 2014, the Company closed the acquisition of Cardium interests contiguous with Tamarack's existing Cardium interest in Wilson Creek, Alberta (the "**Wilson Creek Acquisition**") for an aggregate purchase price of approximately $168.5 million prior to certain closing adjustments. Immediately prior to closing of the Wilson Creek Acquisition, the Company increased its then credit facilities from $110 million to $150 million on the same terms as above. The credit facility was secured by a $300 million demand debenture with a floating charge over all of the assets of the Company and each of its subsidiaries. The Wilson Creek Acquisition was funded in part by bank debt, a temporary bridge facility and a bought deal financing of 16,100,000 subscription receipts (the "**Subscription Receipts**") issued at a price of $7.15 per Subscription Receipt for gross proceeds of approximately $115.1 million (the "**Subscription Receipt Offering**"). Concurrently, a private placement of 1,280,000 common shares of the Company were issued on a "CDE flow-through" basis (the "**CDE Flow-Through Shares**") at a price of $7.85 per CDE Flow-Through Share for gross proceeds of approximately $10.0 million (the "**CDE Flow-Through Share Offering**"). Both the Subscription Receipt Offering and the CDE Flow-Through Share Offering closed on September 26, 2014.

Developments in 2013

On May 7, 2013, Tamarack announced the adoption of an advance notice requirement in connection with shareholders intending to nominate directors in certain circumstances.

On June 17, 2013, the Company increased its then existing revolving operating demand line of credit to $57.5 million from $50 million and its non-revolving acquisition/development demand line of credit remained at $15.0 million for total available facilities of $72.5 million.

On August 20, 2013, Tamarack announced a farm-in agreement (the "**Farm-In Agreement**") with an industry major (the "**Farmor**") to access Cardium lands in the greater Pembina area. Under the Farm-In Agreement, Tamarack committed to drill a minimum of 15 to 20 net wells by December 31, 2016 dependant on whether the Company gets access to certain lands that are currently restricted from access due to regulatory conditions. Tamarack will earn 70% of the Farmor's working interest in the section of lands upon which Tamarack drills and completes a one mile test well, and the Farmor will share in the equipping and tie-in of that well. While in the earning phase of the Farm-In Agreement, Tamarack can propose and drill joint wells on earned lands and the Farmor will have the right to participate or to farmout its residual interest subject to a non-convertible gross overriding royalty and any rights of first refusal. A portion of the farmout lands is subject to a right of first refusal to the Farmor's partners. Tamarack has the right to drill and complete a long reach Cardium well (1.5 to 2.0 miles in length) to earn an interest in two sections. As at December 31, 2015, Tamarack had drilled approximately 12 net wells pursuant to its farm-in commitment, leaving approximately 3 additional net wells to be drilled by December 31, 2016. If the Company receives access by December 31, 2016 to lands which are currently subject to surface access restrictions, then 5 additional net wells will be required to be drilled by December 31, 2017.

On October 9, 2013, Tamarack closed the acquisition of Sure Energy (the "**Sure Energy Acquisition**") pursuant to a court-approved plan of arrangement, for total consideration of $50.3 million, including the assumption of net debt of $32.0 million. The former holders of the common shares of Sure Energy received in aggregate 16,461,966 common shares of Tamarack. The Sure Energy Acquisition added shallow Alberta Viking oil production and development drilling locations to complement the Company's existing Viking oil assets and added heavy oil production and drilling locations to complement the Company's heavy oil assets. Tamarack had 46,168,718 common shares outstanding after giving effect to the Sure Energy Acquisition. Upon completion of the Sure Energy Acquisition, Mr. Jeffrey Boyce was appointed to the Board of Directors, and Tamarack's revolving operating demand facility was increased to $85 million, and the non-revolving acquisition/development demand line of credit was increased to $18 million.

Significant Acquisitions

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 Wilson Creek Acquisition. See "*General Development of the Business – Developments in 2014*" for details regarding the Wilson Creek Acquisition.

The Sure Energy Acquisition was a "significant acquisition" within the meaning of such term under Part 8 of NI 51-102 and a Form 51-102F4 – Business Acquisition Report in respect of the Sure Energy Acquisition was filed on SEDAR within the prescribed period set forth under applicable Canadian securities laws. For additional information regarding the Sure Energy Acquisition, please see "*General Development of the Business – Developments in 2013*" for details regarding the Sure Energy Acquisition.

DESCRIPTION OF THE BUSINESS

Business Objectives and Strategy

Since inception, Tamarack's focus has been on the acquisition of properties primarily in Alberta and also Saskatchewan. Tamarack employs a specific resource play screening criteria to identify and evaluate prospective areas for repeatability, scope, large original oil or gas-in-place per section, which usually suggests substantial reserves, and long life opportunities. These "resource" like play targets can involve conventional or unconventional production methods. The Company plans to control substantial assets in "resource" like plays that are repeatable and relatively predictable. The Company has an extensive inventory of low-risk development oil locations that are economic at various oil prices focused primarily in the Cardium fairway and the Viking fairway in Alberta. Tamarack will continue to expand its current inventory of opportunities through crown land acquisitions and farm-ins on competitors' lands and anticipates that over time, it will have the financial capacity or access to financing if needed to expand its current capital budget if new opportunities are acquired.

Tamarack plans to evaluate 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 believes that this disciplined approach, which includes assessing the potential of the opportunity and the ability of its professional staff to properly evaluate and manage the project, will 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 Tamarack.

The Company also intends to maintain its low cost 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 will ensure it is well positioned to manage through all commodity price cycles.

Specialized Skills and Knowledge

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 to a successful exploration 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 Nature of the Industry

The oil and gas business is cyclical and seasonal. Oil prices fluctuate with changes to global supply or demand for oil, which is dependent on a number of factors, including the health of the global economy and political conditions locally, nationally and internationally as well as access to pipelines and refining facilities. Natural gas prices fluctuate with changes to North American supply or demand, which is dependent on a number of factors, including weather patterns in North America, the health of the North American economy, access to pipeline infrastructure and international markets. In addition, the oil and gas industry in Western Canada is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access to drilling sites and related facilities and may result in the reduction or suspension of operations. Unpredictable weather can also cause delays in implementing and completing field projects. 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 assets are located in areas that are inaccessible other than during the winter months because of the swampy terrain surrounding these sites. Seasonal interruptions in drilling and construction operations do occur but are expected and accounted for in the budgeting and forecasting process.

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. 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, 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, 2015, Tamarack employed 20 full time professionals, and made use of 6 part-time consultants at its head office in Calgary, Alberta and employed 3 full time field employees located at its office in Wilson Creek, Alberta.

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 1, 2016. The effective date of the Statement is December 31, 2015 and the preparation date of the Statement is January 30, 2016.

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 ("**COGE**") Handbook 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 natural gas liquids reserves and the net present value of the estimated Future Net Revenue associated with such reserves as at December 31, 2015 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, 2015
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT & MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED:										
Developed Producing	5,057	4,701	439	336	43,121	38,459	1,645	1,174	14,328	12,620
Developed Non-Producing	41	37	-	-	3,391	2,726	74	47	680	538
Undeveloped	4,635	4,225	250	198	24,968	23,127	938	767	9,985	9,045
TOTAL PROVED	**9,733**	**8,963**	**689**	**534**	**71,480**	**64,312**	**2,657**	**1,988**	**24,992**	**22,203**
PROBABLE	8,583	7,622	585	426	52,590	47,342	2,028	1,495	19,960	17,433
TOTAL PROVED PLUS PROBABLE	**18,315**	**16,585**	**1,274**	**960**	**124,069**	**111,655**	**4,685**	**3,483**	**44,953**	**39,637**

Note:
(1) Columns may not add due to rounding.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% Per Year(1) ($/Boe)	Unit Value Before Income Tax Discounted at 10% Per Year(1) ($/Mcfe)
PROVED:							
Developed Producing	212,690	182,858	158,541	139,623	124,886	12.56	2.09
Developed Non-Producing	8,426	4,424	2,729	1,875	1,379	5.07	0.85
Undeveloped	146,544	94,662	60,381	37,761	22,540	6.68	1.11
TOTAL PROVED	**367,660**	**281,944**	**221,651**	**179,259**	**148,805**	**9.98**	**1.66**
PROBABLE	493,485	297,344	193,592	134,389	97,961	11.10	1.85
TOTAL PROVED PLUS PROBABLE	**861,145**	**579,289**	**415,243**	**313,648**	**246,766**	**10.48**	**1.75**

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

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	212,690	182,858	158,541	139,623	124,886
Developed Non-Producing	8,426	4,424	2,729	1,875	1,379
Undeveloped	146,544	94,662	60,381	37,761	22,540
TOTAL PROVED	**367,660**	**281,944**	**221,651**	**179,259**	**148,805**
PROBABLE	408,873	253,221	168,771	119,578	88,701
TOTAL PROVED PLUS PROBABLE	**776,533**	**535,165**	**390,422**	**298,837**	**237,506**

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, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

(2) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	CAPITAL DEVELOPMENT COSTS ($000s)	ABANDONMENT & RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX ($000s)	INCOME TAX ($000s)	FUTURE NET REVENUE AFTER INCOME TAX ($000s)
Total Proved	1,242,185	117,011	496,729	195,091	65,694	367,660	-	367,660
Total Proved plus Probable	2,472,182	264,070	895,443	365,874	85,649	861,145	84,613	776,533

FUTURE NET REVENUE BY PRODUCTION TYPE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE[(3)]	
			($/Boe)	($/Mcf)
Total Proved	Light and Medium Oil[(1)]	168,520	14.04	2.34
	Heavy Oil[(1)]	2,725	4.61	0.77
	Conventional Natural Gas[(2)]	50,406	5.25	0.87
	Total	**221,651**	**9.98**	**1.66**
Proved plus Probable	Light and Medium Oil[(1)]	297,495	13.47	2.25
	Heavy Oil[(1)]	12,031	11.33	1.89
	Conventional Natural Gas[(2)]	105,717	6.41	1.07
	Total	**415,243**	**10.48**	**1.75**

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Unit values are based on Company net reserves.
(4) 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, 2015 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, 2015 were $52.06/Bbl for light and medium crude oil, $41.98/Bbl for heavy oil, $19.49/Bbl for natural gas liquids and $2.85/Mcf for natural gas. The average realized price on a total oil equivalent basis was $34.43/BOE.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	CRUDE OIL				CONVENTIONAL NATURAL GAS	NATURAL GAS LIQUIDS				
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40⁰ API ($Cdn/Bbl)	Hardisty Bow River 25⁰ API ($Cdn/Bbl)	Hardisty Heavy 12⁰ API ($Cdn/Bbl)	AECO/NIT Spot[(1)] ($Cdn/ MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Edmonton C5+ ($Cdn/Bbl)	INFLATION RATES %/Year	EXCHANGE RATE ($US/$Cdn)
Forecast										
2016	44.67	55.89	45.21	39.20	2.57	9.76	38.73	60.16	0.7	0.7350
2017	55.20	66.47	55.20	48.55	3.14	15.88	46.91	70.95	1.3	0.7667
2018	63.47	73.21	61.05	53.85	3.47	24.09	52.58	78.05	1.8	0.8017
2019	71.00	81.35	68.23	60.36	3.80	30.49	59.42	86.58	1.8	0.8167
2020	74.77	84.57	71.34	63.29	3.99	33.69	62.81	90.00	1.8	0.8333
2021	78.24	87.88	74.38	66.11	4.13	34.95	65.25	93.46	1.8	0.8417
2022	81.75	92.01	78.16	69.59	4.30	36.45	68.33	97.79	1.8	0.8417
2023	85.37	96.24	81.92	73.02	4.48	38.06	71.46	102.23	1.8	0.8417
2024	87.32	98.17	84.07	75.12	4.60	38.79	72.90	104.29	1.8	0.8417
2025	88.90	99.94	85.59	76.49	4.70	39.50	74.22	106.16	1.8	0.8417
2026	90.54	101.79	87.16	77.90	4.79	40.23	75.58	108.13	1.8	0.8417
2027	92.22	103.69	88.78	79.33	4.88	40.96	76.98	110.14	1.8	0.8417
2028	93.90	105.55	90.39	80.78	4.96	41.70	78.38	112.12	1.8	0.8417
2029	95.62	107.49	92.05	82.24	5.05	42.45	79.81	114.18	1.8	0.8417
2030	97.40	109.49	93.76	83.79	5.15	43.21	81.31	116.31	1.8	0.8417
2031+	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	1.8	0.8417

Note:
(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, 2015 against such Reserves as at December 31, 2014 based on forecast price and cost assumptions:

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
	Proved (Mbbls)	Probable (Mbbls)	Proved + Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved + Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved + Probable (Mbbls)
December 31, 2014	**8,485**	**8,069**	**16,555**	**17**	**7**	**24**	**1,469**	**1,427**	**2,895**
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	1,354	(202)	1,152	-	-	-	485	(31)	454
Technical Revisions	(564)	(441)	(1,005)	902	578	1,480	279	98	376
Acquisitions(1)	1,892	1,213	3,105	-	-	-	758	589	1,348
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(84)	(57)	(141)	-	-	-	(67)	(54)	(121)
Production	(1,350)	-	(1,350)	(230)	-	(230)	(267)	-	(267)
December 31, 2015	**9,733**	**8,583**	**18,315**	**689**	**585**	**1,274**	**2,657**	**2,028**	**4,685**

	CONVENTIONAL NATURAL GAS			BOE		
	Proved (Mmcf)	Probable (Mmcf)	Proved + Probable (Mmcf)	Proved (Mbbls)	Probable (Mbbls)	Proved + Probable (Mbbls)
December 31, 2014	**42,985**	**39,591**	**82,576**	**17,135**	**16,101**	**33,236**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	12,206	(1,751)	10,455	3,873	(525)	3,348
Technical Revisions	5,197	420	5,617	1,483	305	1,788
Acquisitions(1)	21,205	16,493	37,698	6,184	4,551	10,735
Dispositions	(27)	(30)	(57)	(5)	(5)	(10)
Economic Factors	(2,724)	(2,133)	(4,857)	(605)	(467)	(1,072)
Production	(7,362)	-	(7,362)	(3,074)	-	(3,074)
December 31, 2015	**71,480**	**52,590**	**124,069**	**24,992**	**19,960**	**44,953**

Notes:
(1) Includes reserve additions from earning wells that were drilled on the Company's Cardium farm-in.
(2) 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.

(a) 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	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Natural Gas (Mmcf)		NGLs (Mbbls)		Oil Equivalent (Mboe)	
	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
Prior(2)	1,676	2,181	-	-	1,183	2,283	54	137	1,927	2,698
2013	1,243	2,624	-	-	3,410	4,748	178	243	1,989	3,658
2014	1,588	3,628	-	-	5,091	9,488	166	279	2,603	5,489
2015	1,337	4,635	44	250	14,121	24,968	563	938	4,298	9,985

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) 2012 was the first year Tamarack's reserves were attributed in this manner.

(b) 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	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Natural Gas (Mmcf)		NGLs (Mbbls)		Oil Equivalent (Mboe)	
	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End	First Attributed(1)	Cumulative at Year End
Prior(2)	1,367	1,917	25	25	2,615	5,299	135	244	1,964	3,070
2013	2,584	3,849	-	25	6,628	10,607	329	488	4,018	6,130
2014	3,023	6,261	-	-	16,137	26,225	564	938	6,276	11,570
2015	1,218	6,766	133	386	16,864	35,653	630	1,394	4,792	14,488

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) 2012 was the first year Tamarack's reserves were attributed in this manner.

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 changes 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.

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.

	FORECAST PRICES AND COSTS ($000s)	
Year	**Total Proved Reserves**	**Total Proved Plus Probable Reserves**
2016	18,903	32,319
2017	65,160	84,869
2018	55,113	95,618
2019	33,146	81,064
2020	22,610	71,676
2021	-	160
2022	-	-
2023	-	-
2024	-	-
2025	115	-
2026	-	-
2027	-	-
Subtotal	195,046	365,705
Remainder	45	169
Total	195,091	365,874
10% Discounted	156,450	284,604

Note:

(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.

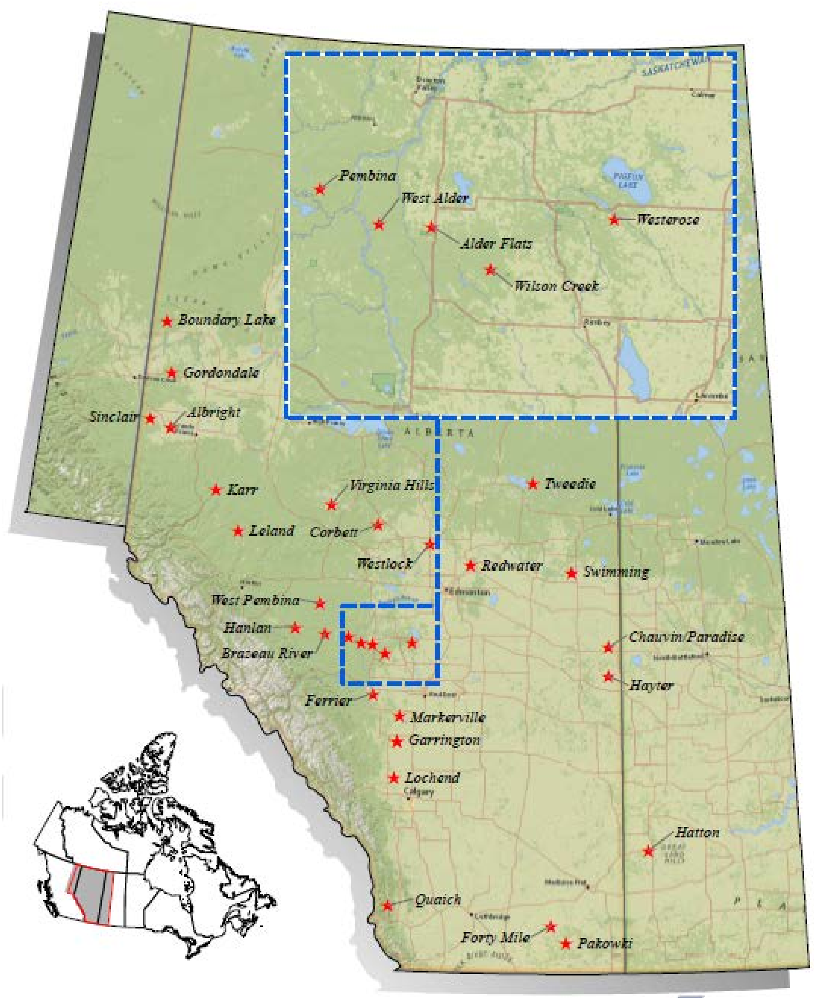
Tamarack typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

The Company expects to fund its 2016 capital program with internally generated cash flow, cash resources on hand, and potentially debt, although the program has been structured to maintain balance sheet strength. Tamarack may also consider completing an equity offering if available on favourable terms. 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 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 December 31, 2015. Information in respect of current production is average production, net to its working interest, except where otherwise indicated.

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 province of Alberta, with very minor assets in Saskatchewan. A summary of the important oil and gas properties by area as at December 31, 2015 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 & Viking:

Cardium Area - Wilson Creek / Alder Flats

Tamarack has interests in 227.3 (171.4 net) sections of land in the Wilson Creek / Alder Flats area of Alberta. At year-end 2015, the Company had proved developed producing reserves of 9,800 mboe and proved plus probable reserves of 30,196 mboe that were booked to 184 (160.8 net) producing Cardium and 96 (53.6 net) wells producing from other zones including a 52% interest in the Pekisko Gas Unit. Proved undeveloped drilling locations of 51 (44.4 net) were included in the evaluation. Tamarack operates two oil batteries, one with 3,800 bbl/d capacity and the other with 1,000 bbl/d, a 52% owned 30 mmcf/d gas plant, and ownership of 100% in a 6 mmcf/d gas plant. The two operated oil batteries are pipeline-connected to the Pembina Pipeline.

Cardium Area - Pembina / Garrington / Lochend

Tamarack has interests in 45.7 (27.6 net) sections of land in the Pembina, Garrington and Lochend areas of Alberta. At year-end 2015, proved developed producing reserves of 1,577 mboe and proved plus probable reserves of 5,794 mboe were booked to 34 (20.5 net) producing wells. Proved undeveloped drilling locations of 19 (12.0 net) were included in the evaluation.

Viking Area – Redwater / Westlock

Tamarack has interests in 60.1 (55.1 net) sections of land in the Redwater and Westlock areas of Alberta. Proved developed producing reserves of 971 mboe and proved plus probable reserves of 4,522 mboe were booked to 98 (80.5 net) producing wells. Proved undeveloped drilling locations of 42 (33.8 net) were included in the evaluation. Tamarack trucks all of its production from this area to various sales points near the city of Edmonton, Alberta.

Saskatchewan Heavy Oil:

Heavy Oil – Hatton

Tamarack has interests in 33.3 (33.3 net) sections of land in the Hatton area of Saskatchewan. Proved developed producing reserves of 480 mboe and proved plus probable reserves of 1,381 mboe were booked to 7 (7.0 net) producing wells. Proved undeveloped drilling locations of 4 (4.0 net) were included in the evaluation. Tamarack operates a 1,200 bbl/d oil battery in the Hatton area.

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, 2015.

	CRUDE OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Cardium Area	241	198	71	57.4	97	53.6	35	18
Viking Area	97	81.2	13	13	1	0.5	4	3.5
Heavy Oil Area	6	6	6	6	-	-	-	-
Other	10	8.7	10	9.3	327	269.2	136	84.5
Total	**354**	**293.9**	**100**	**85.7**	**425**	**323.3**	**175**	**106**

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

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	229,795	177,126	236,675	161,516	466,470	338,642
Saskatchewan	34,976	34,976	6,895	6,244	41,872	41,220
Total	264,771	212,102	243,570	167,760	508,342	379,862

Tamarack had 264,771 gross acres (107,149 gross hectares) and 212,102 net acres (85,835 net hectares) of undeveloped land as at December 31, 2015 located in Alberta and Saskatchewan. No Reserves have been assigned to these lands. The Company has no work commitments currently scheduled on these lands. Tamarack expects that 18,300 gross (17,980 net) acres will expire during 2016.

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 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.

A list of the Company's derivative financial instruments as at December 31, 2015, can be found in note 5(c) of the Notes to the Consolidated Financial Statements for the years ended December 31, 2015 and 2014.

Tax Horizon

Tamarack was not required to pay income taxes during the year ended December 31, 2015. 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 2018.

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, 2015.

Expenditure	**Year Ended December 31, 2015 ($000s)**
Property acquisition costs – Unproved properties (1)	402.6
Property acquisition costs – Proved properties (2)	44,828.5
Corporate acquisition costs	-
Exploration costs (3)	440.8
Development costs (4)(5)	60,644.7
Other	1,114.6
Total	107,431.2

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, 2015.

	Development Wells	
	Gross	**Net**
Light and Medium Oil	17.0	15.6
Heavy Oil	-	-

Natural Gas	-	-
Service	-	-
Dry and Abandoned	-	-
Stratigraphic Test	-	-
Total	**17.0**	**15.6**

In 2016 and contingent on commodity price levels, the Company expects to drill approximately 12 (10.3 net) wells at its Wilson Creek / Alder Flats area in Alberta and will continue to focus on drilling wells that will generate the highest rates of return while fulfilling the remainder of Tamarack's 2016 farm-in commitments. 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)	2015	2014	2013	Three Year Average
Proved Reserves				
Finding, development and acquisition cost	**13.26**	38.98	31.20	26.22
Finding and development costs	**10.95**	37.66	33.20	24.43
Acquisition costs	**15.04**	39.96	30.45	27.42
Proved plus Probable Reserves				
Finding, development and acquisition cost	**7.20**	27.50	23.96	19.27
Finding and development costs	**(4.06)**	27.25	26.81	17.04
Acquisition costs	**11.46**	27.68	23.36	20.28

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 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. Finding and development 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 finding and development costs related to reserves additions for that year

Finding and developments 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, 2015, 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 Light & Medium Crude Oil (bbl/d)	Gross Heavy Crude Oil (bbl/d)	Gross Conventional Natural Gas (Mcf/d)	Gross Natural Gas Liquids (bbl/d)	Gross Barrel of Oil Equivalent (boe/d)
Total Proved					
Wilson Creek	2,034	-	9,298	428	4,011
Alder Flats	161	-	6,041	228	1,396
Other Properties	895	650	7,840	132	2,983
Total	**3,090**	**650**	**23,178**	**787**	**8,390**

Total Proved Plus Probable					
Wilson Creek	2,311	-	9,841	449	4,400
Alder Flats	222	-	8,242	308	1,904
Other Properties	959	845	8,405	145	3,350
Total:	**3,492**	**845**	**26,488**	**902**	**9,654**

Note:
(1) Columns may not add due to rounding.

2015 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2015, 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.

	Quarter Ended				Year End
	Mar. 31, 2015	Jun. 30, 2015	Sept. 30, 2015	Dec. 31, 2015	Dec. 31, 2015
Average Daily Production(1)					
Light and Medium Oil (bbl/d)	4,029	3,029	3,499	4,258	3,703
Heavy Oil (bbl/d)	498	627	660	620	602
Natural Gas (Mcf/d)	17,864	16,972	22,005	23,229	20,038
NGLs (Bbl/d)	588	507	890	1,218	803
Total (BOE/d)	8,092	6,992	8,717	9,968	8,448
Average Net Production Prices Received					
Light and Medium Oil ($/bbl)	48.33	61.21	54.39	47.16	52.06
Heavy Oil ($/bbl)	39.18	51.73	49.15	26.79	41.98
Natural Gas ($/Mcf)	2.91	2.80	3.04	2.66	2.85
NGLs ($/bbl)	25.43	25.87	13.78	18.22	19.49
Total ($/BOE)	34.75	39.82	34.64	30.23	34.43
Royalties Paid					
Light and Medium Oil ($/bbl)	4.33	3.60	3.96	3.33	3.8
Heavy Oil ($/bbl)	9.32	12.74	13.91	8.01	11.14
Natural Gas ($/Mcf)	0.29	0.09	0.25	0.05	0.17
NGLs ($/bbl)	5.80	7.27	5.11	6.13	5.97
Total ($/BOE)	3.78	3.45	3.81	2.8	3.43
Production Costs (2)(3)(4)					
Light and Medium Oil ($/bbl)	10.79	11.73	11.82	11.45	11.45
Heavy Oil ($/bbl)	24.36	17.96	29.43	20.41	23.08
Natural Gas ($/Mcf)	0.51	0.37	0.57	0.38	0.46
NGLs ($/bbl)	-	-	-	-	-
Total ($/BOE)	12.55	12.43	14.05	12.2	12.81
Netback Received					
Light and Medium Oil ($/bbl)	33.21	45.88	38.62	32.38	36.81
Heavy Oil ($/bbl)	5.50	21.04	5.81	(1.62)	7.77
Natural Gas ($/Mcf)	2.12	2.34	2.22	2.23	2.22
NGLs ($/bbl)	19.63	18.60	8.68	12.09	13.52
Total ($/BOE)	18.42	23.94	16.78	15.23	18.19

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 natural gas liquids 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, 2015 for each of the important properties comprising Tamarack's assets.

Property	Light & Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	NGLs (Bbl/d)	Total (BOE/d)
Cardium Area	2,989	-	14,198	774	6,130
Viking Area	692	-	255	1	736
Heavy oil Area	-	602	255	-	644
Other	22	-	5,330	28	938
TOTAL	**3,703**	**602**	**20,038**	**803**	**8,448**

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 23, 2016, there are 114,937,425 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, 2015:

	Price Range ($ per Common Share)		
2015	**High**	**Low**	**Volume**
January	$3.94	$2.75	7,623,442
February	$4.45	$3.51	6,396,887
March	$4.46	$3.50	4,963,550
April	$4.80	$4.05	6,105,684
May	$4.67	$3.57	9,464,115
June	$4.03	$3.48	8,884,837
July	$3.58	$2.51	7,335,671
August(1)	$2.89	$1.83	6,502,520
September	$2.73	$2.21	10,117,821
October	$3.25	$2.22	13,937,520
November	$3.15	$2.64	5,961,032
December	$3.05	$2.58	6,913,463
2016			
January	$3.29	$2.16	7,499,917
February	$3.57	$2.87	7,851,003
March (1 – 23)	$3.80	$2.98	11,196,665

Note:

(1) On August 24, 2015, in connection with Tamarack's graduation to the TSX, the Common Shares were voluntarily delisted from the TSX-V and commenced trading on the TSX. All trading prices prior to this time are from the TSX-V.

Prior Sales

During the financial year ended December 31, 2015, the Company granted an aggregate of 727,000 options, each option entitling the holder thereof to acquire one Common Share, the particulars of which are set forth in the following table:

Option Grants

Date of Grant	Number of Options Issued(1)	Exercise Price ($)
November 14, 2014	7,000	4.38
April 2, 2015	50,000	4.15
July 25, 2015	100,000	2.62
December 18, 2015	570,000	2.75
Total Issued:	**727,000**	2.84

Note:

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

Except as set forth below, no additional unlisted securities of the Company were issued during the financial year ended December 31, 2015.

RSU Grants

On December 18, 2015, the Company granted 1,416,000 restricted share units ("**RSUs**") pursuant to its restricted share unit plan (the "**RSU Plan**"). Additionally, on April 2, 2015, the Company granted 25,000 RSUs, and on July 27, 2015, the Company granted 18,000 RSUs. 4,333 RSUs were exercised during 2015. As of

December 31, 2015, there were 1,861,167 RSUs outstanding. Each RSU entitles the holder thereof upon settlement to receive on Common Share in accordance with the RSU Plan. The RSU grants vest one-third on the first, second and third anniversary of the date of grant.

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 24, 2016, there are 1,155,007 TAC Preferred Shares issued and outstanding. Assuming all TAC Preferred Share exchange rights are exercised, then 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
Brian Schmidt *Alberta, Canada*	President and Chief Executive Officer Director since June 17, 2010	President and Chief Executive Officer of the Company. He is also currently a board of director of Aspenleaf Energy Limited, a private company and is the Vice Chair of the Canadian Association of Petroleum Producers and is an industry 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
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.
Floyd Price[1][2][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 is also currently a director of La Luna Resources, a privately held oil and gas entity based in the United States and Colombia since January 2015. Mr. Price 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 was also previously a director of Nemaha Oil and Gas LLC from October 2011 to April 2014, and Source Energy LP from June 2010 to October 2015, both of which are privately held oil and gas entities based in the United States.
Dean Setoguchi[1][3] *Alberta, Canada*	Director since June 17, 2010	Mr. Setoguchi is 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.
Jeffrey Boyce[2][3] *Alberta, Canada*	Director since October 9, 2013	Mr. Boyce has been President of Evsam Holdings Ltd., a privately held investment company, since October 2013. Mr. Boyce was formerly the Lead Executive director of PetroAmerica Oil Corp. a TSX-V company, from September 2009 until its acquisition by Gran Tierra Energy Inc. in January 2016. Mr. Boyce has been a director of Arpetrol Inc., a TSX-V listed oil and natural gas exploration, development and production corporation, since March 2011. Mr. Boyce was also a director of Northern Shield Resources Inc., a Canadian-based mineral exploration company from 2007 to 2014. Prior thereto, Mr. Boyce was Chief Executive Officer and Chairman of the Sure Energy Ltd. board of directors from August 2006 until its acquisition by the Company on October 9, 2013. Mr. Boyce was also President of Sure Energy Ltd. from August 2006 to September 2010.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Noralee Bradley *Alberta, Canada*	Director since December 17, 2015	Ms. Bradley is a partner at the law firm of Osler, Hoskin & Harcourt LLP, a national law firm, since January 2006. Her practice is focused on mergers and acquisitions, financings and corporate and board governance and she has been the main legal advisor and special counsel in mergers involving both public and private companies, friendly and hostile takeover bids and complicated plans of arrangement. 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.
Ron Hozjan *Alberta, Canada*	Vice President, Finance and Chief Financial Officer	Mr. Hozjan has been Vice President, Finance and Chief Financial Officer of the Company since June 2010 and previously served as a director of the Company from June 2010 to June 2011. Prior thereto, he was Vice President, Finance and Chief Financial Officer and a director of privately-held Tamarack Valley Energy Ltd., a predecessor entity to the Company, from August 2009 to June 2010. Mr. Hozjan was also the Chief Financial Officer and Vice President, Finance of privately-held Vaquero Resources Ltd. . from September 2005 to August 2009.
Dave Christensen *Alberta, Canada*	Vice President, Engineering	Mr. Christensen has been Vice President, Engineering of the Company since April 2014. Prior thereto, he was the Development Engineering Manager for the West Region with Bonavista Energy Corp. from January 2009 to March 2014. Mr. Christensen is a professional engineer.
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.
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.
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.
Rummy Basra *Alberta, Canada*	Corporate Secretary	Ms. Basra is a partner at the law firm of Osler, Hoskin & Harcourt LLP, a national law firm, since March 2014. Prior thereto, Ms. Basra was an associate with Osler, Hoskin & Harcourt LLP since April 2006. Ms. Basra's practice is focussed on public and private mergers & acquisitions, financings and corporate governance.

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.*

As of March 24, 2016, 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 3,106,326 Common Shares, representing approximately 2.7% 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. On March 30, 2015, Laricina and its subsidiaries filed for creditor protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**") from the Court of Queen's Bench of Alberta (the "**Court**"). On January 28, 2016, Laricina was granted a final court order from the Court 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. Laricina has paid in full all accounts in respect of its CCAA proceedings and has set aside a reserve of $1.8 million to pay the remaining unpaid proven claims and outstanding disputed claim. Resolution of the disputed claim will continue on a timetable set by the parties or the Court.

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 and Floyd Price, all of whom are financially literate, as such term is defined in NI 52-110. Each of Mr. Setoguchi, Mr. Price and Mr. MacKenzie 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 investing in early stage companies in the oil and gas, technology and real estate sectors since 1990. While leading the Lincoln Group of Companies, Mr. MacKenzie has occasionally served as a director and/or executive officer of some of the companies in which the Lincoln Group has invested in including having served as President of privately-held Avant Garde Energy Corp. from February 2006 until its acquisition by Tamarack in June 2010 and now serves as a director of privately-held Halo Exploration Ltd. (formerly Fano Energy Inc.) since its inception in February 2011. 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.

Floyd Price

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 is also currently a director of La Luna Resources, a privately held oil and gas entity based in the United States and Columbia since January 2015. Mr. Price 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, as well as Source Energy LP from June 2010 to October 2015 and Nemaha Oil and Gas LLC from October 2011 to April 2014, both of which are privately held oil and gas entities based in the United States. Prior thereto, Mr. Price was employed by U.S.-based Apache Corporation where he served a number of roles including having served as Executive Vice President from February 2003 to October 2009, Executive Vice President for Eurasia, Latin America and New Ventures between 2004 and 2010, President of Apache Canada Ltd. from 1999 to 2004 and President of several of Apache Corporation's international exploration and production subsidiaries from 1995 to 1999. In all of these roles, Mr. Price was responsible for capital and general and administrative budgeting and the operational results thereto.

Mr. Price received his Masters of Science degree from the University of Michigan and his Bachelor of Arts degree from Rutgers College in New Jersey, USA.

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 Company has not adopted specific policies and procedures for the engagement of non-audit services. The Audit Committee reviews the engagement of non-audit services as required.

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, 2015	December 31, 2014
Audit fees(1)	296,995	$140,000
Audit-related fees(2)	45,000	251,000
Tax fees(3)	-	80,000
All other fees(4)	-	-
Total fees	**$341,995**	**$471,000**

Notes:

(1) Paid or are payable for the audit of Tamarack's annual financial statements.

(2) For assurance and related services that are reasonably related to the performance of the audit or review of financial statements and services provided in connection with statutory and regulatory filings and are not reported under the audit fees' item above.

(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 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. Any natural gas export for longer than two years or in excess of 30,000 m^3/day requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires the approval of the Governor in Council.

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 2015, the Company realized an average price of $52.06/bbl on sales of light crude oil, $41.98/bbl on sales of heavy crude oil, reflecting decreases of 40% and 39%, respectively, over the average prices of $87.29/bbl and $68.33/bbl realized during 2014. These decreases are consistent with period-over-period decreases of 40% in the Edmonton Par average price for light oil and 47% for the Hardisty Heavy benchmark price for heavy oil. In comparison, during the same period, the US dollar-denominated average West Texas Intermediate price decreased by approximately 48%.

The Company realized an average price on sales of natural gas of $2.85/Mcf in 2015, a 33% decline from the average price of $4.28/Mcf realized in 2014. The realized price of natural gas in the prior year reflected an increase in demand for natural gas in the January to April 2014 period, caused by unanticipated severe weather conditions.

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.

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.

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, natural gas liquids, sulphur and natural gas production. The royalty regime is a significant factor in the profitability of production operations. 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.

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 will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 Mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Royalties for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36 percent. Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between one percent to nine percent, depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are one percent when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of nine percent when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of one percent to nine percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent when oil is priced at $55 per barrel or less and increase for every dollar of market price of oil increase above $55 up to 40 percent when oil is priced at $120 or higher.

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

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

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

- Coalbed methane wells will receive a maximum royalty rate of five percent for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of five percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of five percent for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of five percent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF, prior to March 31, 2016.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is three percent of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7 percent of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("**fourth tier oil**", "**third tier oil**", "**new oil**" and "**old oil**") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (conventional oil produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (conventional oil produced from a well having a finished drilling date on or after October 1, 2002) or new oil (conventional oil that is not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of fourth tier oil but differs for third tier oil (conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002) and new oil (conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002). Non-heavy oil other than southwest designated oil uses the same definitions as heavy oil for third and fourth tier oil, but differs for but new oil (conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994) and old oil (conventional oil not classified as third or fourth tier oil or new oil). Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for old oil, 10.0 for new oil and third tier oil and 12.5 for fourth tier oil. The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (gas produced from a gas well having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (gas produces from a gas well having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). Associated gas is classified as fourth tier gas (gas produced from an oil well with a finished drilling date on or after October 1, 2002, or with a finished drilling date before October 1, 2002 where the gas-oil ratio for the month exceeds 3,500 m^3 of gas per m^3 of oil, and is not third tier gas or new gas, third tier gas (gas produced from an oil well with a finished drilling date on or after February 9, 1998 and before October 1, 2002 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties), new gas (gas produced from an oil well having a finished drilling date before February 9, 1998 that received special approval prior to October 1, 2002 to produce oil and gas concurrently without gas-oil ratio penalties); old gas is not used as classification for associate gas.

On December 9, 2010, the Government of Saskatchewan enacted the Freehold Oil and Gas Production Tax Act, 2010 which replaced the existing Freehold Oil and Gas Production Tax Act and was intended to facilitate more efficient payment of freehold production taxes by industry. Two regulations with respect to this legislation are: (i) The Freehold Oil and Gas Production Tax Regulations, 2012 (Saskatchewan) which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) The Recovered Crude Oil Tax Regulations, 2012 (Saskatchewan) which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

Effective April 1, 2013, the Saskatchewan Resources Credit, which is a credit factor used in the formulas to calculate Crown royalty and freehold production tax rates applicable to old oil, new oil, third tier oil (i.e. wells drilled before October 2002) was reduced by 0.25% to either 0.75% or 2.25% of the value of production, depending on the type of well.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005 providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005 providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

- Royalty/Tax Regime for High Water-Cut Oil Wells granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011 the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and came into effect on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Effective January 29, 2015, the Government of Saskatchewan released the Saskatchewan Petroleum Research Incentive to encourage research, development and demonstration of new technologies to enhance the recovery and development of oil and gas resources. Costs incurred in connection with the research, development or demonstration of a new technology may be eligible for cost recovery from the Government of Saskatchewan.

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. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Alberta

The Alberta Energy Regulator (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.

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.

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 ABOGCA 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.

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 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee 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.

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.

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.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit temperature rise below 1.5° Celsius, through implementing successive nationally determined contributions. At the time of the Paris Agreement, Canada committed to reduce GHG emissions by 30% below 2005 levels by 2030. Technical details regarding how Canada intends to meet its target have not been finalized.

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

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below their intensity targets, and (4) by contributing to the Climate Change and Emissions Management Fund (the "**Fund"**). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions starting in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. This price will increase in real terms each year after that. On-site combustion in conventional oil and gas will be levied starting January 1, 2023 to allow time for that sector to reduce emissions. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("CCR"), in which sector specific output-based carbon allocations will be used to ensure competitiveness. Finally, Alberta plans to reduce methane emissions from oil and gas operations by 45% by 2025 through applying new emissions design standards to new facilities and initiating a 5-year voluntary Joint Initiative on Methane Reduction and Verification to address venting and fugitive emissions from existing facilities. Regulatory mandated standards will be implemented starting in 2020 to ensure the methane reduction 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.

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 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.

Market Conditions

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.

Effect of Commodity Prices on Operational and Financial Results

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

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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or 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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. A prolonged period of adverse market conditions may impede the Company's ability to finance planned capital expenditures. In addition, 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. In each case, the Company's ability to maintain and grow its reserves and fully exploit its properties for the benefit of the shareholders of the Company would be adversely affected. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by Organization of Petroleum Exporting Countries (OPEC) and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Company's ability to obtain equity or debt financing on acceptable terms.

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 into 2016, world oil prices have continued to significantly decline. 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.

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 Risk

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, which include 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 be required to be repaid.

Additional Indebtedness

The Company may need to find additional sources of financing to repay this amount when it becomes due. There can be no guarantee that the Company will be able to obtain financing on terms acceptable to it or at all at such time.

Furthermore, if the Company becomes unable to pay its debt service charges or otherwise commits an event of default under the terms of the Credit Facility, as the case may be, then the Company may be forced to sell some of its assets or properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Company's lenders and other creditors and only the remainder, if any, would be available to the Company.

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.

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 is 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.

The GLJ Report is effective as of December 31, 2015 and has not been updated and thus does not reflect changes in Tamarack's reserves since that date.

Properties With No Attributed Reserves

The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, forecasted commodity price assumptions, cost estimates and access to infrastructure. These and other factors could lead to the delay or the acceleration of projects related to these properties.

Risks Associated with Acquisitions

Acquisitions of oil and gas properties or companies, including the Sure Energy Acquisition, the Wilson Creek Acquisition, and the Wilson Creek Cardium Acquisitions 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.

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Tamarack makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions, including the Sure Energy Acquisition, the Wilson Creek Acquisition and the Wilson Creek Cardium 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 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.

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.

Environmental Concerns

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*".

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 of 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*". 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.

Climate Change Legislation

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 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*".

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*".

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.

Potential 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.

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.

Limitations of 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 Risks

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.

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.

In accordance with the terms of the Sure Energy Acquisition, Mr. Boyce received 1,271,719 Common Shares in exchange for his Sure Energy Shares which were tendered under the terms of the transaction.

Certain directors and officers of the Company have participated in private placements and public offerings undertaken by the Company since the commencement of the Company's most recently completed financial year on the same basis as other arm's length subscribers to such offerings.

Noralee Bradley, a director of the Company and Rummy Basra, the Corporate Secretary of the Company, are each partners of Osler, Hoskin & Harcourt LLP, which law firm provides legal services to the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares of the Company is Computershare Trust Company of Canada at its offices 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 other than the acquisition agreement between the Company and an industry major in connection with one of the Wilson Creek Cardium Acquisitions. See "*General Development of the Business – Developments in 2015*".

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the GLJ Report prepared by GLJ, an independent reserves evaluator. As of March 24, 2016, to the knowledge of the Company, the directors, officers, employees and consultants of GLJ who participated in the preparation of the GLJ Report who were in a position to directly influence the preparation or outcome of the preparation of the GLJ 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.

Certain reserves estimates contained in filings made by the Company under NI 51-102 during the most recently completed financial year were prepared by Martin Malek, who is considered a qualified reserves evaluator in accordance with NI 51-101. As of March 23, 2016, Mr. Malek beneficially owned, directly and indirectly, less than 1% of the outstanding securities of the Company

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 July 23, 2015 relating to the annual and special meeting of shareholders held on August 27, 2015. 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, 2015.

DEFINITIONS

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

"**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 established on July 31, 2015 with a syndicate of Canadian chartered banks, consisting of a revolving credit facility in the amount of $155 million and an operating facility in the amount of $10 million;

"**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;

"**February 2014 Offering**" means the Company's bought deal offering of 14,000,000 Common Shares at a price of $4.30 for aggregate gross proceeds of $60.2 million;

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

"**GLJ Report**" means the independent engineering report dated February 1, 2016 and evaluating the crude oil, natural gas and NGLs reserves of the Company effective as of December 31, 2015;

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

"**March 2016 Offering**" means the Company's bought deal offering of 13,014,000 Common Shares at a price of $2.92 for aggregate gross proceeds of $38.0 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*;

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

"**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;

"**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.

"**Wilson Creek Acquisition**" means the 2014 acquisition of Cardium interests contiguous with Tamarack's existing Cardium interest in Wilson Creek, Alberta; and

"**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.

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	standard 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 6 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 Acquisition and the Wilson Creek Cardium Acquisitions;
- oil and natural gas production levels;
- 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;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the completion and timing of the farm-in pursuant to the farm-in and option agreement dated effective August 1, 2013 between Tamarack and an industry major (the "**Farm-In Agreement**") and any other farm-in arrangements that Tamarack has entered into, or may enter into in the future;
- the ability of the Company to achieve drilling success consistent with management's expectations;
- the impact of the Farm-In Agreement on the Company's operations, infrastructure, inventory and opportunities, financial condition and overall strategy;
- drilling plans 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;
- tax horizon and future income taxes;
- use of Credit Facility funds;
- the Company's capital program and guidance for 2016;
- expectations regarding commodity prices in 2016;
- deployment of the Company's 2016 capital program;
- the expected allocation of the Company's 2016 capital expenditure budget;
- the source of funds for the Company's 2016 expenditure budget;
- the value of the capital expenditures to be made by the Company during the first and second halves of 2016;
- the use of proceeds from the March 2016 Offering;
- the impact of the Wilson Creek Cardium Acquisitions on the Company's operations, infrastructure, inventory and opportunities, financial condition, access to capital and overall strategy;
- 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.

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources described can be profitably produced in the future.

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 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 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.

NON-IFRS MEASURES

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds generated from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also contains the terms "net debt" and "netbacks", 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 net debt (bank debt net of working capital 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 its profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a boe basis by deducting royalties and operating costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts.

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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, 2015, 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 Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	12/31/2015	Canada	-	415,243	-	415,243

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 1, 2016.

"Originally Signed by"

John E. Keith, 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") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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) "*Floyd Price*"
Floyd Price, Director

(signed) "*David MacKenzie*"
David MacKenzie, Director

(signed) "*Jeff Boyce*"
Jeff Boyce, Director

March 23, 2016

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.
- (e) 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, when applicable, 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

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 $25,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than $25,000 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.