Annual Information Form

For the Year Ended December 31, 2014

March 11, 2015

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TAMARACK VALLEY ENERGY LTD.

BACKGROUND

Tamarack Valley Energy, Ltd ("**Tamarack**" or the "**Company**") (formerly Tango Energy Inc.) 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, and a change of name of the Company from "Tango Energy Inc." to "Tamarack Valley Energy Ltd."

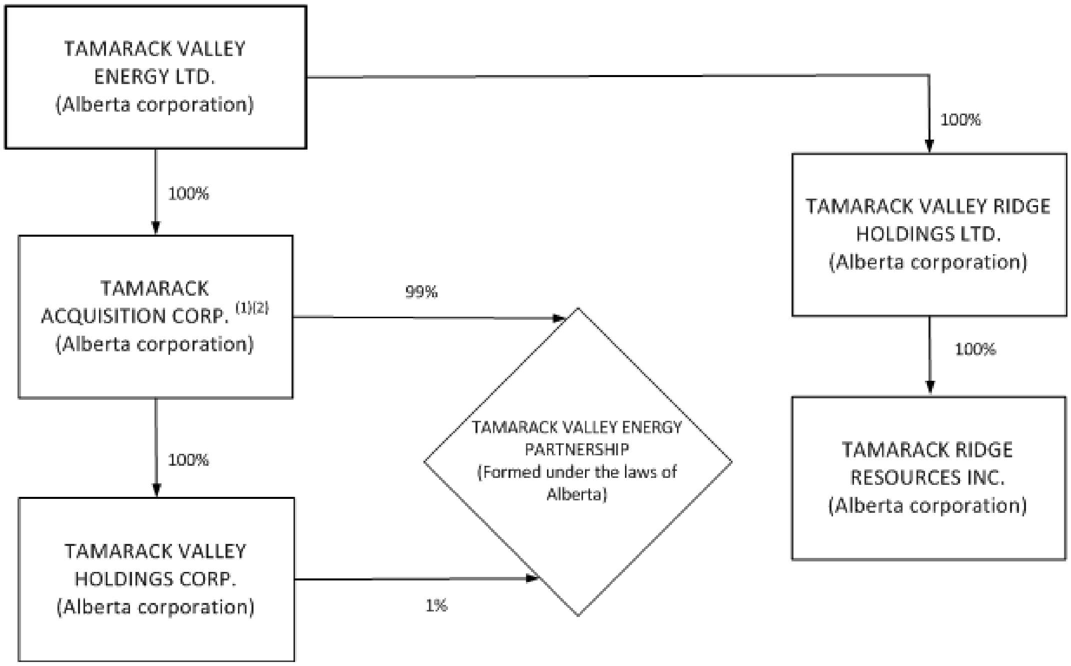
We seek to provide growth for our shareholders by identifying, securing and developing high-quality assets within the Western Canadian Sedimentary Basin and by executing a technically disciplined, full-cycle approach to oil and natural gas exploration.

Tamarack is a "reporting issuer" or the equivalent in each of the Provinces of Canada. The Common Shares trade on the TSX-V under the symbol "TVE".

Our 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 diagram to the left illustrates the inter-corporate relationships among the Company and its subsidiaries and affiliated entities as of the date hereof.

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."

Note on Share References

On July 16, 2012, Tamarack effected a consolidation of the Common Shares on the basis of one (1) post-consolidated Common Share for every twelve (12) pre-consolidated Common Shares. All references to Common Shares, subscription receipts and share prices prior to the consolidation date have been restated to reflect the share consolidation. As a result, restated figures may be slightly greater than or less than their pre-consolidation equivalent due to rounding.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Since the Restructuring Transaction, Tamarack has focused on acquiring and developing an attractive land base within our core Cardium and Viking light oil plays. We have continued to successfully execute our business strategy to build a sustainable, predictable and reliable growth company while maintaining a strong financial position.

The following is a summary of the key developments occurring in our business over the past three years.

Recent Developments

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.

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 Offering**"). On January 29, 2014, the Company announced an increase in the size of the February Offering from 7,000,000 Common Shares to 14,000,000 Common Shares for total gross proceeds of $60.2 million. Proceeds of the February Offering were used to reduce bank indebtedness, partially fund the Company's continuing capital program and for general corporate purposes. The February Offering closed on February 19, 2014. Concurrent with the February 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 of Tamarack 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 simultaneous 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 of 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 will be subject to its next 364 day extension by May 30, 2015. If not extended, the credit facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date. The interest rate on both the revolving facility and operating facility is determined through a pricing grid which is based on a net debt to cash flow ratio. The interest rate will vary 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 will vary 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 has been secured by a $300,000,000 supplemental debenture with a floating charge over all assets. As the available lending limits of the credit facilities 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. The next scheduled review is in May 2015.

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 Existing Credit Facility is 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 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 of March 31, 2015 the Company had satisfied approximately 39% to 52% of the drilling commitment, depending on whether it will be obligated to drill 15 or 20 wells. The Company estimates the capital expenditures required to fulfill the remainder of this commitment will be between $22 million and $40 million.

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.

Developments in 2012

On February 8, 2012, the Company's existing revolving operating demand line of credit with a Canadian chartered bank was increased from $12 million to $15 million. The Company elected not to renew the non-revolving acquisition/development demand line of credit.

On April 17, 2012, Tamarack closed the acquisition of private company, Echoex (the "**Echoex Acquisition**"), for total transaction value, including the assumption of Echoex debt, of approximately $60.5 million. Through the Echoex Acquisition, Tamarack acquired high quality, high netback light oil assets, located predominantly in the Redwater area of Alberta and along the Redwater Viking trend. Production and reserves from Echoex materially enhanced Tamarack's exposure to the Viking light oil resource play. Also on April 17, 2012, Tamarack closed a bought deal financing with a group of underwriters of 5,500,000 subscription receipts (the "**2012 Subscription Receipts**") at a price of $3.00 per Subscription Receipt for aggregate gross proceeds of $16.5 million (the "**2012 Subscription Receipt Offering**"). Concurrent with closing of the Echoex acquisition, the net proceeds from the 2012 Subscription Receipt Offering were released from escrow and Common Shares were issued to holders of 2012 Subscription Receipts. The entire net proceeds of the 2012 Subscription Receipt Offering were used to reduce outstanding indebtedness under the then credit facilities, thereby freeing up borrowing capacity which the Company was then able to draw upon and apply to accelerate the Company's 2012 capital program. In connection with the Echoex Acquisition, Mr. Sheldon Steeves, formerly the President, Chief Executive Officer and a director of Echoex, was appointed to the Board of Directors.

On April 17, 2012, in connection with the 2012 Subscription Receipt Offering and the Echoex Acquisition, the Company's existing revolving operating demand line of credit was increased from $15 million to $45 million.

On July 16, 2012, the Company implemented a share consolidation of all of the Company's issued and outstanding Common Shares on the basis of one (1) post-consolidation Common Share for every twelve (12) pre-consolidation Common Shares (the "**Consolidation**").

On August 16, 2012, the Company announced that its then existing revolving operating demand line of credit was increased to $50 million and its non-revolving acquisition/development demand line of credit was increased to $45 million from $15 million.

Significant 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

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 play targets can involve conventional or unconventional production methods. We plan to control substantial assets in resource plays. Tamarack currently has identified the Cardium play and the Alberta shallow Viking oil play as two of our core resource plays that have been de-risked and are being developed. Tamarack will expand our current inventory of opportunities through crown land acquisitions and farm-ins on competitors' lands and anticipates that we will have the financial capacity to expand our 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. We believe that this disciplined approach, which includes assessing the potential of the opportunity and the ability of our 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 some of our non-core assets where opportunities exist to enhance the overall value of Tamarack.

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 our personnel have the skills and that Tamarack will have the resources to achieve our 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. 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 we believe we have 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 our interpretation of the value of such lands and on that basis, we would 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 us meet this challenge. We believe our distinct competitive advantage is through our scientific, integrated approach in generating drilling prospects.

Employees

As at December 31, 2014, Tamarack employed 13 full time professionals, 7 administrative employees and made use of 4 part-time consultants at our head office in Calgary, Alberta and employed 3 full time field employees located at our 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 our products or services or to purchase the majority of our 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 our 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

We anticipate that we 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, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs, and while we would seek to finance these activities in the most prudent manner possible, we 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 our capitalization significantly. Transactions involving the issuance of securities may be dilutive. The inability of Tamarack to access sufficient capital for our operations could have a material adverse effect on our 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 our responsibilities to protect the environment and we will be taking such steps as required to ensure compliance with environmental legislation in all jurisdictions in which we operate. 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, we anticipate 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 our 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 25, 2015. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is February 20, 2015.

Disclosure of Reserves Data

The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The 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.

All of Tamarack's reserves are "onshore" and located in Western Canada.

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, 2014 FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:										
Developed Producing	4,683	4,180	-	-	30,322	26,681	1,110	804	10,846	9,431
Developed Non-Producing	174	159	17	16	3,175	2,539	80	52	800	650
Undeveloped	3,628	3,244	-	-	9,488	8,558	279	223	5,489	4,894
TOTAL PROVED	**8,485**	**7,583**	**17**	**16**	**42,985**	**37,778**	**1,468**	**1,079**	**17,135**	**14,974**
PROBABLE	8,069	7,012	7	6	39,591	35,221	1,427	1,057	16,102	13,945
TOTAL PROVED PLUS PROBABLE	**16,555**	**14,595**	**24**	**22**	**82,576**	**72,999**	**2,895**	**2,136**	**33,236**	**28,920**

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	220,557	184,042	157,350	137,865	123,246	16.68	2.78
Developed Non-Producing	20,671	13,712	10,298	8,357	7,120	15.85	2.64
Undeveloped	99,483	57,666	32,313	16,214	5,617	6.60	1.10
TOTAL PROVED	**340,711**	**255,420**	**199,961**	**162,437**	**135,983**	**13.35**	**2.23**
PROBABLE	452,535	260,446	163,191	108,425	74,899	11.70	1.95
TOTAL PROVED PLUS PROBABLE	**793,246**	**515,866**	**363,151**	**270,862**	**210,883**	**12.56**	**2.09**

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

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

RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	220,557	184,042	157,350	137,865	123,246
Developed Non-Producing	20,671	13,712	10,298	8,357	7,120
Undeveloped	99,483	57,666	32,313	16,214	5,617
TOTAL PROVED	**340,711**	**255,420**	**199,961**	**162,437**	**135,983**
PROBABLE	362,224	213,818	136,923	92,628	64,910
TOTAL PROVED PLUS PROBABLE	**702,935**	**469,239**	**336,884**	**255,065**	**200,893**

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 DEDEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	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	1,071,445	121,675	430,893	157,582	20,584	340,711	-	340,711
Total Proved plus Probable	2,264,570	278,802	798,297	366,876	27,348	793,246	90,311	702,935

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE(3)	
			($/Boe)	($/Mcf)
Total Proved	Light and Medium Oil(1)	156,092	15.85	2.64
	Heavy Oil(1)	410	26.27	4.38
	Natural Gas(2)	43,458	8.50	1.42
	Total	**199,961**	**13.35**	**2.23**
Proved plus Probable	Light and Medium Oil(1)	290,614	14.92	2.49
	Heavy Oil(1)	587	26.79	4.47
	Natural Gas(2)	71,951	7.64	1.27
	Total	**363,151**	**12.56**	**2.09**

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 this Statement, the terms set out below have the indicated meanings:

"**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 following terms, used in the preparation of the GLJ Report and this AIF, have the following meanings:

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

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

"**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.

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

"**future prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

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

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

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated allowances; and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate yearend statutory tax rates, taking into account future tax rates already legislated.

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coalbed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and 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.

"**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**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.

"**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

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

"**production**" means extraction of oil and/or natural gas and associated NGL's from a reservoir. recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

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

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

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

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

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

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

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

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

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

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

"**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.

"**solution gas**" means natural gas dissolved in crude oil.

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

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

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

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

Pricing Assumptions

The following tables detail the reference prices and inflation rate assumptions as at December 31, 2014 utilized by GLJ in the GLJ Report for estimating reserves data. GLJ is an independent qualified reserves evaluator.

Tamarack's weighted average realized sales prices for the year ended December 31, 2014 were $87.29/Bbl for light and medium crude oil, $68.38/Bbl for heavy oil, $47.49/Bbl for natural gas liquids and $4.28/Mcf for natural gas. The total oil equivalent (combined) was $60.38/BOE.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40^0 API ($Cdn/Bbl)	Hardisty Bow River 25^0 API ($Cdn/Bbl)	Hardisty Heavy 12^0 API ($Cdn/Bbl)	AECO Gas Price(1) ($Cdn/MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	INFLATION RATES %/Year	EXCHANGE RATE ($US/$Cdn)
Forecast									
2015	62.50	64.71	55.00	48.89	3.31	19.63	52.91	2.0	0.85
2016	75.00	80.00	68.00	60.68	3.77	32.00	60.80	2.0	0.875
2017	80.00	85.71	72.86	65.09	4.02	38.57	65.14	2.0	0.875
2018	85.00	91.43	77.71	69.49	4.27	41.14	69.49	2.0	0.875
2019	90.00	97.14	82.57	73.90	4.53	43.71	73.83	2.0	0.875
2020	95.00	102.86	87.43	78.30	4.78	46.29	78.17	2.0	0.875
2021	98.54	106.18	90.26	80.87	5.03	47.78	80.70	2.0	0.875
2022	100.51	108.31	92.06	82.51	5.28	48.74	82.31	2.0	0.875
2023	102.52	110.47	93.90	84.17	5.53	49.71	83.96	2.0	0.875
2024	104.57	112.67	95.77	85.87	5.71	50.70	85.63	2.0	0.875
2025+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.875

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, 2014 against such Reserves as at December 31, 2013 based on forecast price and cost assumptions:

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

	LIGHT AND MEDIUM OIL			HEAVY 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, 2013	**5,198**	**4,722**	**9,920**	**19**	**41**	**60**	**663**	**728**	**1,391**
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	2,373	1,515	3,887	-	-	-	272	356	628
Technical Revisions	42	(567)	(525)	3	(4)	(1)	(53)	(109)	(161)
Acquisitions	2,262	2,465	4,727	-	-	-	807	499	1,305
Dispositions	(29)	(35)	(64)	-	-	-	(51)	(51)	(102)
Economic Factors	(196)	(30)	(226)	(5)	(30)	(35)	(55)	3	(52)
Production	(1,164)	-	(1,164)	-	-	-	(114)	-	(114)
December 31, 2014	**8,485**	**8,069**	**16,555**	**17**	**7**	**24**	**1,469**	**1,427**	**2,895**

	TOTAL NATURAL GAS			BOE		
	Proved (Mmcf)	Probable (Mmcf)	Proved + Probable (Mmcf)	Proved (Mbbls)	Probable (Mbbls)	Proved + Probable (Mbbls)
December 31, 2013	**24,676**	**19,207**	**43,883**	**9,992**	**8,693**	**18,684**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	8,448	10,941	19,389	4,052	3,695	7,747
Technical Revisions	2,663	357	3,020	437	(620)	(184)
Acquisitions	14,915	10,882	25,797	5,554	4,778	10,332
Dispositions	(1,044)	(1,321)	(2,365)	(254)	(307)	(561)
Economic Factors	(1,823)	(474)	(2,297)	(560)	(136)	(696)
Production	(4,852)	-	(4,852)	(2,087)	-	(2,087)
December 31, 2014	**42,985**	**39,591**	**82,576**	**17,135**	**16,102**	**33,236**

Note:
(1) 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 our 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 two 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 Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (Mmcf)		NGLs (Mbbls)		Oil Equivalent (Mbbls)	
	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

Note:

(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 Oil (Mbbls)		Heavy 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

Note:

(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.

Although we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our 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 our 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**
2015	19,781	41,162
2016	60,672	102,636
2017	52,918	122,653
2018	21,683	76,809
2019	621	21,696
2020	162	-
2021	-	166
2022	-	-
2023	1,582	1,582
2024	-	-
2025	119	-
2026	-	-
Subtotal	157,538	366,703
Remainder	44	173
Total	157,582	366,876
10% Discounted	129,936	294,842

Notes:

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

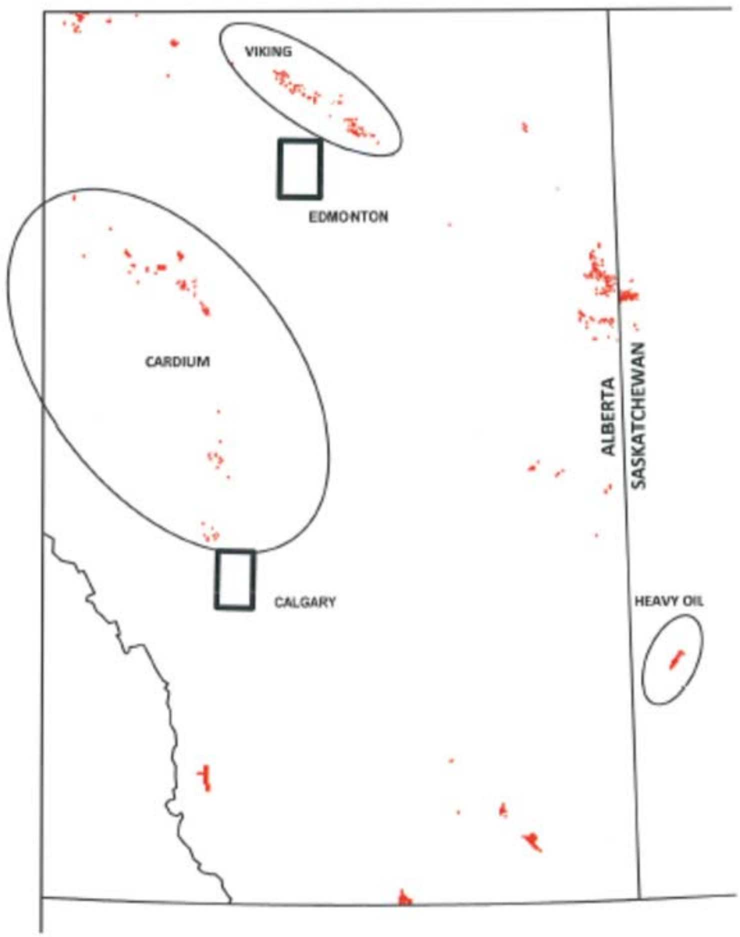
Tamarack typically has available three sources of funding to finance our capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

We expect to fund our 2015 capital program with internally generated cash flow, cash resources on hand, and an increase in debt. 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 or will make the development of any of our properties uneconomic.

Other Oil and Gas Information

The following is a description of our principal oil and natural gas properties that are on production or under development as at December 31, 2014. Information in respect of current production is average production, net to our 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 located in the provinces of Alberta, with very minor assets in Saskatchewan. A summary of the important oil and gas properties by area as at December 31, 2014 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:

<u>Cardium Area - Wilson Creek / Alder Flats</u>

Tamarack has interests in 110.7 (73.5 net) sections of land in the Wilson Creek / Alder Flats area of Alberta. Proved developed producing reserves of 5.237 mmboe and proved plus probable reserves of 15.746 mmboe were booked to 128 (80.1 net) producing wells and a 52% interest in the Pekisko Gas Unit. Proved undeveloped drilling locations of 19 (16.4 net) were included in the evaluation. Tamarack operates a 3,800 bbl/d oil battery and a 52% owned 30 mmcf/d gas plant. The operated oil battery is pipeline-connected to the Pembina Pipeline.

Cardium Area - Pembina / Garrington / Lochend

Tamarack has interests in 30.5 (19.2 net) sections of land in the Pembina, Garrington and Lochend areas of Alberta. Proved developed producing reserves of 2.024 mmboe and proved plus probable reserves of 7.118 mmboe were booked to 32 (20.5 net) producing wells. Proved undeveloped drilling locations of 19 (12 net) were included in the evaluation. Tamarack operates a 700 bbl/d oil battery and owns a 10% in a non-operated oil battery in the Lochend area. The Company also operates a 51% owned 700 bbl/d oil battery in the Garrington area.

Viking Area – Redwater / Westlock / Foley Lake

Tamarack has interests in 78.6 (73.2 net) sections of land in the Redwater, Westlock and Foley Lake areas of Alberta. Proved developed producing reserves of 1.434 mmboe and proved plus probable reserves of 5.214 mmboe were booked to 96 (80.5 net) producing wells. Proved undeveloped drilling locations of 49 (39.5 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 / Manitou Lake

Tamarack has interests in 17 (17 net) sections of land in the Hatton area of Saskatchewan. Proved developed producing reserves of 237 mboe and proved plus probable reserves of 635 mboe were booked to 9 (9 net) producing wells. Proved undeveloped drilling locations of 3 (3 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, 2014.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Cardium Area	130	91.4	28	16.3	11	5.7	36	17.8
Viking Area	97	81.5	19	17.3	-	-	-	-
Heavy Oil Area	9	9.0	10	10	-	-	-	-
Other	-	-	-	-	310	269.4	186	123.3
Total	**236**	**181.9**	**57**	**43.6**	**321**	**275.1**	**222**	**141.1**

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	231,494	178,649	194,704	129,545	426,198	308,194
Saskatchewan	28,923	28,285	7,398	6,750	36,321	35,035
Total	260,417	206,934	202,102	136,295	462,519	343,229

Tamarack had 260,417 gross acres (104,167 gross hectares) and 206,934 net acres (82,774 net hectares) of undeveloped land as at December 31, 2014. No Reserves have been assigned to these lands. The lands are located in Alberta and Saskatchewan. The Company has no work commitments are currently scheduled on these lands. Tamarack expects that 44,214 gross (39,734 net) acres will expire during 2015.

In calculating gross and net acreage, we count an acreage twice if Tamarack holds interests in separate prospective formations under the same surface area under separate leases. We count 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 where we have two prospective formations under one lease and the acreage was counted once.

Forward Contracts

We are 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 our exposure to fluctuations in commodity prices, increase the certainty of funds from operations and to protect acquisition and development economics. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. We are exposed to losses in the event of default by the counterparties to these derivative instruments, but manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

A list of the Companies derivative financial instruments as at December 31, 2014, can be found in note 5(d) of the Notes to the Consolidated Financial Statements for the years ended December 31, 2014 and 2013.

Abandonment and Reclamation Costs

Tamarack uses our internal historical costs to estimate our abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2014, the Company had approximately 638 net wells including water source, injection and standing wells for which we expect to incur abandonment and reclamation costs.

The abandonment and reclamation obligation included in the Company's financial statements differs from the amount deducted in the reserves evaluation, as the GLJ Report forecasts abandonment costs only for wells assigned reserves and no allowance was made for reclamation of existing wellsites or the abandonment and reclamation of any facilities in the GLJ Report. The following table sets forth abandonment costs deducted in the estimation of the Company's future net revenue associated with the total proved plus probable reserves as provided in the GLJ Report:

Period	**Abandonment and Reclamation Costs Undiscounted ($000s)**	**Abandonment and Reclamation Costs Discounted at 10% ($000s)**
Total liability as at December 31, 2014	**27,348**	**4,403**
Anticipated to be paid in 2015	**609**	**578**
Anticipated to be paid in 2016	**151**	**136**
Anticipated to be paid in 2017	**98**	**84**

The decommissioning liabilities recorded in the Company's financial statements result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. Tamarack estimates the total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $43 million, which will be incurred over the next 40 years.

Tax Horizon

Tamarack was not required to pay income taxes during the year ended December 31, 2014. 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 we 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, 2014.

Expenditure	**Year Ended December 31, 2014 ($000s)**
Property acquisition costs – Unproved properties [(1)]	6,436
Property acquisition costs – Proved properties [(2)]	134,949
Corporate acquisition costs	-
Exploration costs [(3)]	600
Development costs [(4)(5)]	146,435
Other	483
Total	288,903

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, 2014.

	Development Wells	
	Gross	**Net**
Light and Medium Oil	52.0	43.0
Heavy Oil	6.0	6.0
Natural Gas	-	-
Service	1.0	1.0
Dry and Abandoned	-	-
Stratigraphic Test	1.0	1.0
Total	**60.0**	**51.0**

In 2015 and contingent on improving commodity prices, we expect to drill approximately 11 (9.9 net) wells in Alberta and will continue to focus on drilling primarily for oil prospects.

Finding and Development Costs

The following table summarizes our finding and development costs for the periods indicated.

($/Boe) (1)(2)(3)	2014	2013	2012	Three Year Average
Proved Reserves				
Finding, development and acquisition cost	38.98	31.20	28.87	34.53
Finding and development costs	37.66	33.20	26.17	33.70
Acquisition costs	39.96	30.45	31.00	35.06
Proved plus Probable Reserves				
Finding, development and acquisition cost	27.50	23.96	23.56	25.74
Finding and development costs	27.25	26.81	20.68	25.58
Acquisition costs	27.68	23.36	25.71	25.82

Notes:

(1) *Including changes in future development capital expenditures.*

(2) *We have presented finding and development costs both including and excluding acquisitions and dispositions. While NI 51-101 requires that the effects of acquisitions and dispositions be excluded, we have included these items because we believe that acquisitions and dispositions can have a significant impact on our ongoing reserve replacement costs and that excluding these amounts could result in an inaccurate portrayal of our cost structure.*

(3) *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.*

Production Estimates

The following table sets out the first year production forecast of volumes of our 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"*.

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Barrel of Oil Equivalent (boe/d)
Total Proved					
Cardium Area	2,412	-	9,665	447	4,470
Viking Area	767	-	414	1	837
Heavy oil Area	299	-	419	-	369
Other Properties	22	-	5,867	42	1,043
Total	**3,501**	**-**	**16,365**	**490**	**6,719**
Total Proved Plus Probable					
Cardium Area	2,812	-	11,136	496	5,164
Viking Area	804	-	433	1	877
Heavy oil Area	337	-	470	-	415
Other Properties	24	-	6,070	44	1,080
Total:	**3,977**	**-**	**18,109**	**541**	**7,536**

Notes:

(1) Columns may not add due to rounding.

2014 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2014, 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, 2014	Jun. 30, 2014	Sept. 30, 2014	Dec. 31, 2014	Dec. 31, 2014
Average Daily Production[(1)]					
Light and Medium Oil (bbl/d)	2,099	2,797	3,040	3,772	2,932
Heavy Oil (bbl/d)	83	181	346	413	257
Natural Gas (Mcf/d)	11,093	12,033	12,462	17,518	13,292
NGLs (Bbl/d)	151	219	302	576	313
Total (BOE/d)	4,182	5,203	5,765	7,681	5,717
Average Net Production Prices Received					
Light and Medium Oil ($/bbl)	94.82	98.83	95.83	67.83	87.29
Heavy Oil ($/bbl)	77.30	77.80	77.59	54.84	68.38
Natural Gas ($/Mcf)	4.93	4.37	4.13	3.91	4.28
NGLs ($/bbl)	79.84	55.22	47.74	36.18	47.49
Total ($/BOE)	65.09	68.27	66.62	47.89	60.38
Royalties Paid					
Light and Medium Oil ($/bbl)	10.27	11.31	11.19	8.10	10.05
Heavy Oil ($/bbl)	24.04	11.51	24.51	15.89	18.69
Natural Gas ($/Mcf)	0.63	0.78	0.56	0.29	0.53
NGLs ($/bbl)	15.73	13.87	5.6	9.26	9.95
Total ($/BOE)	7.86	8.87	8.87	6.20	7.78
Production Costs [(2)(3)(4)]					
Light and Medium Oil ($/bbl)	11.60	13.26	12.71	11.01	12.03
Heavy Oil ($/bbl)	27.53	26.76	28.78	22.91	26.14
Natural Gas ($/Mcf)	0.46	0.46	0.52	0.49	0.48
NGLs ($/bbl)	-	-	-	-	-
Total ($/BOE)	13.25	14.35	14.84	12.59	13.68
Netback Received					
Light and Medium Oil ($/bbl)	72.95	74.27	71.93	48.71	65.20
Heavy Oil ($/bbl)	25.73	39.53	24.30	16.04	23.56
Natural Gas ($/Mcf)	3.84	3.13	3.06	3.12	3.26
NGLs ($/bbl)	64.11	41.35	42.13	26.92	37.55
Total ($/BOE)	43.98	45.05	42.91	29.10	38.91

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, 2014 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	1,791	-	5,778	246	3,000
Viking Area	1,059	-	466	1	1,138
Heavy oil Area	-	257	309	-	309
Other	82	-	6,739	66	1,271
TOTAL	**2,932**	**257**	**13,292**	**313**	**5,717**

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 the date hereof, there are 77,928,466 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-V 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, 2014:

	Price Range ($ per Common Share)		
2014	**High**	**Low**	**Volume**
January	$4.72	$3.59	17,307,676
February	$5.04	$4.33	9,347,652
March	$6.08	$4.75	15,756,373
April	$6.30	$5.61	12,542,122
May	$6.12	$5.26	7,400,507
June	$6.86	$5.72	8,402,177
July	$6.73	$5.64	5,602,627
August	$7.61	$5.90	12,846,194
September	$7.85	$6.27	17,584,619
October	$6.82	$4.27	16,862,104
November	$5.27	$2.92	11,171,107
December	$3.50	$2.57	13,965,224

Prior Sales

During the financial year ended December 31, 2014, the Company granted an aggregate of 1,223,000 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 ($)
March 17, 2014	40,000	$5.00
February 13, 2014	125,000	$4.50
February 24, 2014	400,000	$4.65
August 13, 2014	466,000	$6.82
October 27, 2014	192,000	$4.75
Total Issued:	**1,223,000**	

Note:

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

No additional unlisted securities of the Company were issued during the financial year ended December 31, 2014.

RSU Grants

On August 13, 2014, the Company granted 411,000 restricted share units ("**RSUs**") pursuant to its restricted share unit plan (the "**RSU Plan**"). 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.). Each TAC Preferred Share is exchangeable by the holder for 0.9615385 of a Common Share at a price of $3.12 per Common Share equivalent, subject to certain conditions, for a period of five years. Up to one-third of the TAC Preferred Shares may be exchanged by the holder for Common Shares on or after each of the first, second and third anniversary dates from the closing date of the Restructuring Transaction, being June 17, 2010. Tamarack 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 the option plan of Tamarack), (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 the date hereof, there are 1,223,040 TAC Preferred Shares issued and outstanding. Assuming all TAC Preferred Shares are exercised, then Tamarack would issue 1,176,000 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 our 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 Existing 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, as of the date hereof. All directors have been elected to serve as such until the Company's next annual meeting of shareholders, or until his successor is duly elected, unless his 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.
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 Source Energy LP since June 2010, a privately-held oil and gas entity based in the United States. 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.
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-V listed natural gas and natural gas liquids 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

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
		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 is also the Lead Executive director of PetroAmerica Oil Corp. a TSX-V company, a position he has held since September 2009. 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.
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, Vice President, Finance and a director of privately-held Tamarack Valley Energy 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.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Noralee Bradley *Alberta, Canada*	Corporate Secretary	Ms. Bradley is a partner at the law firm of Osler, Hoskin & Harcourt LLP, a national law firm, since January 2006. Prior thereto, Ms. Bradley was a partner with Bennett Jones LLP, a national law firm.

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 11, 2015, 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 2,731,035 Common Shares, representing approximately 3.5% 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

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.

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

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, Floyd Price and Mr. MacKenzie are considered independent under NI 52-110.

Relevant Education and Experience

Dean Setoguchi

Mr. Setoguchi is a chartered accountant and currently Senior Vice President, Liquids Business Unit of Keyera Corp., a TSX listed natural gas and natural gas liquids 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 Source Energy LP since June 2010 and of Nemaha Oil and Gas LLC since October 2011, both of which are privately-held oil and gas entities based in the United States. 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. 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, 2014	December 31, 2013
Audit fees[(1)]	$140,000	$110,000
Audit-related fees[(2)]	251,000	133,000
Tax fees[(3)]	80,000	-
All other fees[(4)]	-	-
Total fees	**$471,000**	**$243,000**

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.

Exemption

As Tamarack is listed on the TSX-V, Tamarack, pursuant to Section 6.1 of NI 52-110, is exempt from the requirements of Part 3 (Composition of the Audit Committee) and Part 5 (Reporting Obligations) of NI 52-110. As such, Tamarack is relying on this exemption.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. Controls relating to land tenure, exploration, development, production, refining, transportation and marketing, among other things, are imposed by legislation and regulation enacted by various levels of government. The pricing and taxation of oil and natural gas is regulated by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, 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, value of refined products, 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 made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB, 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 to be made pursuant to a contract 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 Governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

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. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the ARF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-30% for new and 5% to 35% for old vintages, and rate caps were set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% 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 9% 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 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF or the ARF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to May 27, 2010, and including wells drilled into pools drilled prior to 1985, among other changes. The natural gas deep drilling program has since been extended indefinitely and will be reviewed by the Government of Alberta on a regular basis. The program for conventional oil exploration wells has been terminated.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 metres and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates automatically became subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provided up to a $200 per metre royalty credit for new wells and was primarily expected to benefit smaller producers since the maximum credit available was determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 Mmcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations. The *New Well Royalty Regulation*, pertaining to the same, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 Mmcf of production, retroactive to wells that began producing on or after May 1, 2010;

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

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 Mmcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

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

The Emerging Resource and Technologies Initiative was to be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

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

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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

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

- Deep Royalty Credit Program providing royalty credits for deep non-re-entry wells. Effective April 1, 2014, the Government of British Columbia revised the program to be a two-tier system. Tier one wells must be spud after April 1, 2014, be a horizontal well with a completion point shallower than 1900 metres and have a deep well depth greater than 2500 metres. Tier one wells will attract a minimum 6% royalty. Tier two wells are vertical gas wells with a completion point deeper than 2500 metres and horizontal gas wells with a completion point deeper than 1900 metres. Tier two wells will attract a minimum 3% royalty. Tier two of the royalty credit program has been in place since 2003;

- Deep Re-Entry Royalty Credit Program providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- Deep Discovery Royalty Credit Program providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

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

- Marginal Royalty Reduction Program providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- Ultra-Marginal Royalty Reduction Program providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth ("**TVD**") of less than 2,500 metres in the case of vertical wells, and a TVD of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every metre of ultra-marginal well depth. Pursuant to updates published in March 2014, horizontal wells that spud on or after April 1, 2014 are not eligible;

- Net Profit Royalty Reduction Program providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the lesser of the estimated completion cost and the completion cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In each of 2012, 2013 and 2014, the Government of British Columbia allocated $120 million in infrastructure royalty credits under the Infrastructure Royalty Credit Program. The Government of British Columbia has since allocated another $120 million in royalty credits under the Infrastructure Royalty Credit Program for 2015.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spudded between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. However, recent changes that became effective April 1, 2013, now impose a 3% minimum royalty to wells with deep well and deep re-entry well credits when the net royalty payable for such wells would otherwise be zero for a production month, thereby changing the application of the deep well credits to gross royalty payable.

Also effective April 1, 2013, was the termination of British Columbia's Summer Drilling Credit Program. Any wells drilled on or after this date are no longer eligible to receive the credit. Previously granted credits under this program are not affected by its termination.

Saskatchewan

In Saskatchewan, 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 (having a finished drilling date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

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. Like conventional oil, 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 (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 (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). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with 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.

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.

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 $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 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 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.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and Alberta Energy had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, Alberta Energy announced it is deferring serving shallow rights reversion notices.

This decision was to be revisited in spring 2012 and the formal response from Alberta Energy was communicated to industry in April 2013 when the issuance of shallow rights reversion notices was indefinitely suspended for agreements made prior to 2009. Leases issued after 2009 remain subject to the shallow rights reversion policy.

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.

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.

Climate Change Regulation

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. On January 31, 2010, the federal government committed under the Copenhagen Accord to reducing GHG emissions by 17 per cent from 2005 levels, which is linked to the same target adopted by the United States.

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. The Government of Canada is also currently looking at how to reduce GHG emissions from oil sands operations and conventional crude oil and natural gas extraction. The Government of Canada, however, has not yet passed any broad climate change legislation or regulations that target the oil or natural gas sector.

In addition, on February 16, 2012, Canada's Minister of the Environment announced that Canada, together with Bangladesh, Ghana, Mexico, Sweden and the United States, and supported by the United Nations Environment Programme, had launched a new global initiative called the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants. It is not clear whether this initiative will necessitate federal regulations or legislation.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. The CCEMA and the associated Specified Gas Emitters Regulation require that facilities that have been operating since 2000 or earlier and that emit more than 100,000 tonnes of GHGs per year must reduce their GHG emissions intensity by 12 per cent over the average emissions intensity levels of 2003, 2004 and 2005. Newer facilities are required to reduce their emissions intensity by 2% from baseline levels in the fourth year of commercial operation, 4% of baseline levels in the fifth year, 6% of baseline levels in the sixth year, 8% of baseline levels in the seventh year, 10% of baseline levels in the eighth year and 12% of baseline levels in the ninth year.

The CCEMA contains several compliance mechanisms. In addition to emissions reductions at a regulated emitter's own facilities, emissions credits can also be purchased from other regulated emitters that have reduced their emissions below the prescribed threshold or from non-regulated emitters in Alberta that have generated emissions offsets through activities that result in emissions reductions (in accordance with established protocols published by the Government of Alberta). Regulated emitters can also meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent.

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.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose in $5 increments each year to a final rate of $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008. Unlike the emissions intensity approach taken by the Government of Alberta, the Cap and Trade Act allows for regulations that establish absolute caps on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of

British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

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 and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. 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.

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 Existing Credit Facility or arrange alternative financing when the Existing Credit Facility becomes due or if the lending limits under the Existing 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.

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 and into 2015, world oil prices have declined significantly. Any substantial and extended decline 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-V, 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 Existing Credit Facility is dependent on the borrowing base determined by the lenders to Tamarack under the Existing Credit Facility. The Company is required to comply with covenants under the Existing 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 Existing 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 Existing 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 Existing 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 Existing 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 Existing 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 Existing 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 in calculating reserves quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the 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, 2014 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 and the Wilson Creek Acquisition, 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 and the Wilson Creek Acquisition, 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*".

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 greenhouse gases 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 greenhouse gas 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 greenhouse gas regulations, including increases to the compliance costs contained in the Specified Gas Emitters Regulation, could also have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company 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.

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, the corporate secretary of the Company, is a partner 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 Olympia Trust Company 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 Suncor Energy Inc. in connection with the Wilson Creek Acquisition. See "*General Development of the Business – Developments in 2014*".

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the GLJ Report prepared by GLJ, an independent reserves evaluator. As of the date hereof, 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 Dave Christensen, who is considered a qualified reserves evaluator in accordance with NI 51-101. As of the date hereof, Mr. Christensen beneficially owns, directly and indirectly, less than 1% of the outstanding securities of the Company

KPMG LLP 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.

KPMG LLP, Chartered Accountants, prepared the audit report to Schedule "A" of the business acquisition report of Tamarack dated October 9, 2014 – "*Operating Statement of Revenue, Royalties, Production Expenses and Operating Income*", being the operating statements of the assets acquired pursuant to the Wilson Creek Acquisition. KPMG LLP has confirmed that they were independent of Tamarack within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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

ADDITIONAL INFORMATION

Additional information regarding Tamarack may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the Company's management information circular dated May 1, 2014 relating to the annual and special meeting of shareholders held on June 2, 2014. 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, 2014.

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 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;

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

"**Echoex Acquisition**" means the acquisition by the Company of Echoex pursuant to the terms and conditions of the Echoex Acquisition Agreement;

"**Echoex Acquisition Agreement**" means the pre-acquisition agreement respecting the acquisition of the Echoex Shares dated March 26, 2012 between the Company and Echoex;

"**Echoex Shares**" means, collectively, the outstanding common shares and class B common shares in the capital of Echoex;

"**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;

"**Existing Credit Facility**" means the existing credit facilities of the Company established on August 11, 2014 with a syndicate of Canadian chartered banks, consisting of a revolving credit facility in the amount of $140 million and an operating facility in the amount of $10 million;

"**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 25, 2015 and evaluating the crude oil, natural gas and NGLs reserves of the Company effective as of December 31, 2014;

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

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

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

"**Wilson Creek Acquisition**" means the acquisition 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.

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
McfGE	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 and the Wilson Creek Acquisition;
- 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 operational and financial guidance for 2015;
- the use of proceeds from the February 2014 Offering, the Subscription Receipt Offering and the CDE Flow-Through Share Offering;
- the impact of the Wilson Creek Acquisition 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 Corporation 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 OF RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR FORM 51-101F2

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographical Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary February 20, 2015	CANADA	-	363,151	-	363,151

5. In our opinion, the reserves data respectively 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 25, 2015.

"*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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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 11, 2015

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

5. 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**").

6. 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.

7. A quorum for the transaction of business at a meeting of the Committee shall consist of two members of the Committee.

8. 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.

9. 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.

10. 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.

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

Authority and Reporting

1. In discharging its duties and responsibilities, the Committee shall have the authority to:

   (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

   (b) discuss with the management of the Corporation, its subsidiaries and affiliates and staff of the Corporation, any affected party, contractors and consultants of the Corporation and the auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate;

   (c) engage independent counsel and other advisors (including a second firm of external auditors) as it determines necessary to carry out its duties; and

   (d) set and pay the compensation for any advisors employed by the Committee.

2. The Committee shall after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

Primary Duties and Responsibilities

1. The Committee's primary duties and responsibilities regarding its audit function are to:

   (a) review with the external auditors the audit function generally, the objectives, staffing, locations, co-ordination, and scope of proposed audits of the financial statements of the Corporation;

   (b) review with management and the external auditors, and recommend to the Board for approval and release to shareholders, the quarterly and annual financial statements of the Corporation, together with related reports to shareholders, MD&A associated with such financial statements and, 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

2. 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.