



tamarack valley ENERGY Ltd.

Annual Information Form

For the Year Ended December 31, 2019

March 4, 2020

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The information in this AIF is given as of December 31, 2019 unless otherwise indicated.

TAMARACK VALLEY ENERGY LTD.**BACKGROUND**

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

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

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

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

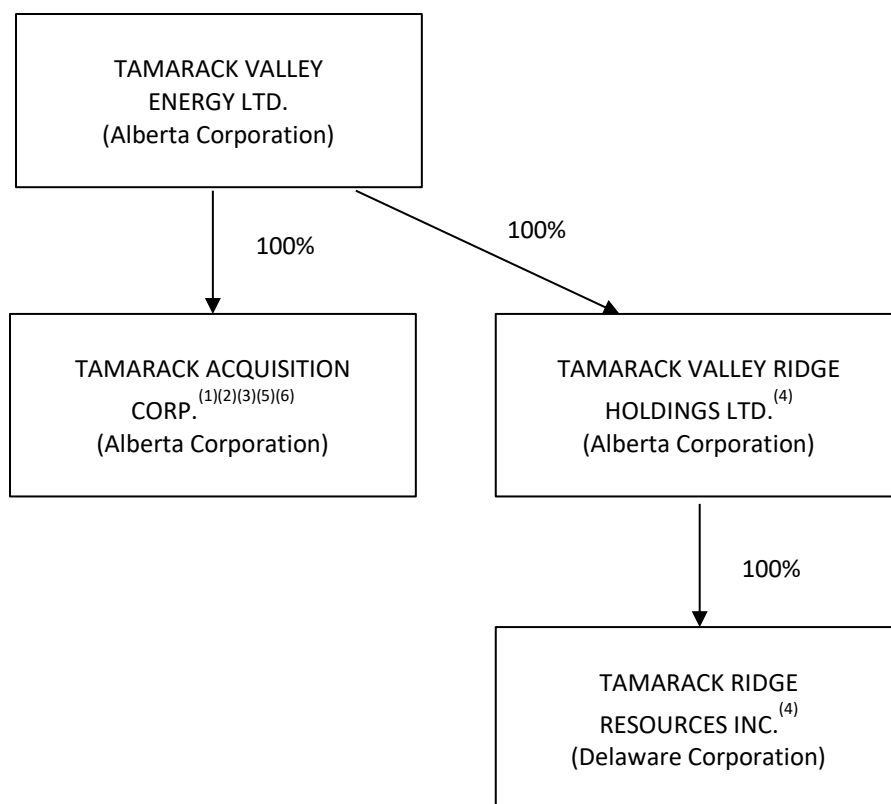
Tamarack is a "reporting issuer" or the equivalent in each of the provinces of Canada. The Common Shares have traded on the TSX under the symbol "TVE" since August 24, 2015. Previously, the Common Shares were trading on the TSX-V.

The Company's head office is located at Suite 600, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8. The registered office of the Company is located at Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P5C5.

See "*Selected Abbreviations*" and "*Definitions*" for an explanation of capitalized terms and expressions, abbreviations and definitions used in this AIF.

Inter-corporate Relationships

The following diagram presents the name and jurisdiction of incorporation of Tamarack's material subsidiaries as at December 31, 2019.



Notes:

- (1) On January 1, 2013, Echoex Ltd. amalgamated with TAC as part of an internal re-organization of Tamarack with the resulting amalgamated corporation assuming the name "Tamarack Acquisition Corp."
- (2) On October 9, 2013, Sure Energy was amalgamated with Alberta 1767001 with the resulting amalgamated corporation, Sure Amalco assuming the name "Sure Energy Inc.". Subsequently, on October 9, 2013, the corporation resulting from the amalgamation of Sure Energy and Alberta 1767001 was amalgamated with TAC with the resulting amalgamated corporation assuming the name "Tamarack Acquisition Corp."
- (3) On December 31, 2015, the Company's subsidiaries Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp., each partners of Tamarack Valley Energy Partnership, dissolved such partnership. On January 1, 2016, Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp. completed a vertical amalgamation under the ABCA to form "Tamarack Acquisition Corp."
- (4) As of the date hereof, no assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd.
- (5) On January 11, 2017, Tamarack Acquisition Corp. and Spur Resources Ltd. (a corporation amalgamated under the ABCA in connection with the Viking Acquisition) completed a horizontal amalgamation under the ABCA to form "Tamarack Acquisition Corp."
- (6) As of the date hereof, the only material subsidiary of Tamarack is Tamarack Acquisition Corp.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

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

Recent Developments

Tamarack's 2019 production averaged 24,072 boe/d (63% oil and NGL), generating adjusted funds flow of \$219.4 million (\$0.97 per share basic and diluted). Tamarack generated an operating netback of \$27.47/boe after realized commodity hedging gains/losses. The Company exited the year with an oil and natural gas liquids ("**NGL**") weighting unchanged from the first quarter of 2019 despite the production curtailments imposed by the Government of Alberta. Tamarack's year-end 2020 net debt to Q4 annualized adjusted funds flow ratio is forecast at less than 1.0 times, with a minimum of \$150 million of liquidity on existing credit facilities.

On January 9, 2020, Tamarack confirmed its 2020 capital budget, announced its associated 2020 guidance and provided an operational update. A capital budget between \$170 and \$180 million for 2020 is expected to be funded entirely from adjusted funds flow, is forecast to maintain volumes consistent with the 2019 annual average production, and is expected to increase Tamarack's oil weighting by 7% to 12% in 2020. The Company also announced the resignation of Mr. Ron Hozjan as Vice President, Finance and Chief Financial Officer of the Company.

Developments in 2019

On January 15, 2019, Tamarack announced its 2019 capital program and provided an operational update. The Company achieved record Q4/18 production of approximately 24,780 boe/d (in line with its previously provided exit guidance range) with an oil and NGL weighting of approximately 66%, while spending approximately \$7.0 million less than the quarterly budget. The Company set its capital budget between \$170 and \$180 million, expected to be fully self-funded, and resulting in an expected annual average production rate of 23,500 – 24,500 boe/d (64-66% oil and NGL). The Company prioritized hedging through 2019 to remain well positioned against volatility in pricing, having entered the year with approximately 25% of annual production protected with hedges. On January 1, 2019, the Government of Alberta's production curtailment order came into effect (the "**Curtailment Order**"). The Curtailment Order was designed to mitigate the wide price differential related to a lack of pipeline capacity, resulting in the Company adjusting its production program timing.

On February 27, 2019, the Company announced its 2018 year-end operating and financial results, provided an operational update, and presented details from the reserves report prepared in accordance with NI 51-101 by GLJ with an effective date of December 31, 2018. Annual 2018 production increased by 20% over the prior year, with an 8% increase in oil and NGL weighting, generating an increase in total adjusted funds flow of 43% in 2018 to \$226.5 million (\$0.99 per share basic and \$0.97 per share diluted). During 2018, Tamarack invested \$219.2 million in total capital expenditures net of dispositions, which included drilling a total of 164 (158.2 net) wells, comprised of 129 (124.7 net) Viking oil wells, 19 (17.8 net) Cardium oil wells, 4 (4.0 net) Penny oil wells, 11 (10.7 net) Redwater oil wells, one exploratory vertical stratigraphic well and one (1.0 net) water source well. Based on GLJ's independent evaluation in 2018, total crude oil reserves grew by 22% for total proved plus probable ("**TPP**"), by 15% for total proved ("**TP**") and 10% for proved developed producing ("**PDP**"), respectively, over the prior year.

On April 4, 2019, the Company announced that the TSX had accepted the notice of intention to commence a new Normal Course Issuer Bid ("**NCIB**"), allowing Tamarack to acquire up to 8,600,000 Common Shares of the Company over a period of twelve months, expiring no later than April 7, 2020.

On May 9, 2019, Tamarack announced its financial and operating results for the three months ended March 31, 2019. In the first quarter, production averaged 23,149 boe/d (64% oil and NGL weighting), reflecting the Company's

compliance with the Curtailment Order. The Company achieved a total adjusted funds flow of \$57.5 million in Q1/19 (\$0.25/share basic and diluted), an operating netback of \$30.11/boe, and invested \$71.2 million in the quarter, with 76% directed to drill, complete and equip 31 (30.2 net) Viking oil wells, 7 (6.1 net) Cardium oil wells and 2.0 net Penny oil wells. Tamarack completed four minor tuck-in acquisitions of assets in the first quarter, totaling \$1.1 million.

On August 8, 2019, Tamarack provided its financial and operating results for the three and six months ended June 30, 2019. During Q2/19, production averaged 24,090 boe/d (63% oil and NGL weighting), which was 4% higher than the previous quarter, and maintained total adjusted funds flow at \$57.9 million. Net production and transportation expenses in the second quarter were 3% lower at \$10.12/boe compared to the same period in the prior year, primarily due to increased production from the lower-cost Veteran area and a reduction in transportation expenses for oil produced at Veteran. The Company increased its syndicated revolving Credit Facility by 20% to \$350 million from \$290 million during the three-month period, and invested \$25.9 million, with 61% directed to drill, complete and equip five (5.0 net) Viking oil wells, as well as complete and bring on production 18 (17.7 net) Viking oil wells and two (2.0 net) Cardium oil wells that were drilled in late Q1/19.

On November 6, 2019, Tamarack released its operating and financial results for the third quarter of 2019. During the quarter, the Company achieved an average corporate production of 24,171 boe/d (62% oil and NGL weighting), which was consistent with the previous quarter and reflected the Company's compliance with the production curtailment. The Company generated \$49.3 million (\$0.22/share basic and diluted) in total adjusted funds flow, and \$24.50/boe in operating netback during the third quarter. \$58.9 million was invested in the quarter to drill, complete and equip 40.6 net Viking oil wells, 2.0 net water injectors, 2.0 net water source wells and 0.9 net Cardium wells. Encouraging waterflood results were announced, allowing corporate decline forecasts to reduce to 34% in 2020 and be under 30% in 2021.

Developments in 2018

On January 15, 2018, Tamarack provided an operational update and announced its 2018 capital program highlights and guidance. Tamarack achieved fourth quarter 2017 production of 22,600 boe/d with an increased oil and NGL weighting of 62%, which is higher than its forecast exit rate of 22,000 boe/d (59% oil and NGL). The Company's strong production performance during 2017 reached a record for Tamarack and was a direct result of its successful second half drilling and completions program coupled with continued enhancements to operational efficiencies and cost control. During most of 2017, Tamarack made a conscious decision to allocate capital to drilling locations and other projects with a higher oil and NGL weighting, which positively impacted its production profile and operating netbacks. The Company expected to be fully self-funded in 2018 and set the 2018 capital budget between \$195 and \$205 million. Tamarack guided for 2018 annual average production between 22,500 and 23,500 boe/d (64 to 66% oil and NGL), with 2018 exit production estimated between 24,000 and 24,500 boe/d (65 to 67% oil and NGL). The estimated year-end 2018 debt to fourth quarter annualized adjusted funds flow ratio was less than 1.0 times with an estimated \$100 million of liquidity on the Company's existing credit facilities.

On March 6, 2018, the Company announced its 2017 year-end operating and financial results and an operations update, along with details from the reserves report prepared in accordance with NI 51-101 by GLJ with an effective date of December 31, 2017. Tamarack's 2017 production averaged 20,136 boe/d (60% oil and NGL), generating adjusted funds flow of \$158.4 million (\$0.70 per share basic and diluted) and an operating netback of \$24.22/boe. On December 31, 2017, net debt stood at \$173.2 million. During 2017, the Company drilled a total of 133 (126.4 net) producing wells and one (1.0 net) injection well. The 133 producing wells included 104 (99.0 net) Viking oil wells, 16 (15.3 net) Cardium oil wells, five (5.0 net) heavy oil wells and three (3.0 net) Mannville wells, as well as five (4.1 net) wells in other areas. Total gross proved reserves at December 31, 2017, as evaluated by GLJ, were 51,761 mboe (60.0% oil and NGL), while total gross proved plus probable reserves were 91,462 mboe (61.7% oil and NGL). During 2017, the Company generated finding and development costs of \$20.70/boe and \$17.88/boe on a total proved and total proved plus probable basis, respectively. Finding, development and acquisition costs, for the same reserve categories, were \$27.86/boe and \$20.91/boe, respectively.

On April 4, 2018, Tamarack received approval from the TSX for an NCIB (the "**former NCIB**") for up to 8,600,000 Common Shares over a period of twelve months commencing on April 6, 2018.

On May 10, 2018, Tamarack released its financial and operating results for the three months ended March 31, 2018. During the quarter, Tamarack achieved corporate production of 23,532 boe/d (63% oil and NGL), increased total adjusted funds flow by 81% to \$58.5 million (\$0.26/share basic, \$0.25/share diluted), maintained healthy net debt to annualized Q1/18 adjusted funds flow ratio of 0.8 times, and improved operating netbacks by 31% to \$30.11/boe due to the increase in oil and NGL weighting. The Company invested \$69.6 million on drilling, completing and equipping 66 wells (64.1 net). Tamarack closed one tuck-in acquisition totaling \$2.5 million and maintained the \$290 million borrowing base on its Credit Facility.

On August 9, 2018, Tamarack provided its financial and operating results for the three and six months ended June 30, 2018. During the quarter, the Company achieved corporate production of 23,853 boe/d (63% oil and NGL), increased operating netbacks to \$34.15/boe due to reduced net production and transportation costs and increased oil and NGL weighting and realized prices. Tamarack invested \$52.7 million in total capital expenditures, which included the drilling, completing and equipping of 43 (41.3 net) wells while maintaining a healthy net debt to annualized Q2/18 adjusted operating field netback of 0.7 times with \$157 million drawn on the Company's \$290.0 million Credit Facility. During the quarter, Tamarack also reduced share dilution by purchasing and cancelling 1,081,000 outstanding Common Shares at a total cost of \$4,421,000 under the former NCIB and spent \$4,000,000 to purchase 970,000 outstanding Common Shares that are held in trust and will be used to settle restricted share units ("**RSUs**") granted pursuant to Tamarack's performance and restricted share unit plan (the "**PRSU Plan**") upon future exercise. The Company also increased its 2018 annual average production guidance to the range of 23,500 to 24,000 boe/d (64 to 66% NGL).

On September 20, 2018, the Company provided a second guidance increase for 2018 annual and exit production to the range of 24,000 to 24,500 boe/d (64 to 66% NGL) as a result of better than expected performance from its Alberta Viking drilling program to date in 2018. Average annual production volumes under its preliminary 2019 budget were increased to the range of 25,500 to 26,500 boe/d and with a capital budget of \$222 million (originally \$250 million with \$28.4 million accelerated into 2018). The Company also provided an operational update for the third quarter, with 56 (54.1 net) wells drilled.

On November 7, 2018, Tamarack released its operating and financial results for the quarter ended September 30, 2018. During the quarter, the Company achieved corporate production of 24,765 boe/d (66% oil and NGL) and operating netbacks of \$36.61/boe. The Company had \$169 million drawn on its \$290 million Credit Facility, and invested \$78.1 million in capital expenditures during the quarter to drill 54 (52.2 net) wells. The Company also announced that, for the nine months ended September 30, 2018, it had spent \$9.4 million to purchase and cancel 2.1 million Common Shares through its former NCIB program.

Developments in 2017

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

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

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

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

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

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

On June 22, 2017, Robert Spitzer was elected as an independent director of the Company.

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

On November 8, 2017, Tamarack released its financial and operating results for the three months ended September 30, 2017, noting, among other things: (i) achieving production of 20,541 boe/d (59% weighted towards oil and NGL); (ii) generating adjusted funds flow (previously referred to as funds from operations) of \$34.8 million; (iii) investing \$74.1 million in capital expenditures to drill 50 (48.6 net) Viking oil wells, eight (8.0 net) Cardium oil wells, one (0.8 net) Ellerslie oil well, one (1.0 net) Mannville gas well, and two (2.0 net) heavy oil wells; (iv) executing on various tuck-in land acquisitions within core areas to bolster Tamarack's footprint, including four separate purchases totaling 145 net sections of land for an aggregate purchase price of \$3.4 million and completing a minor tuck-in acquisition within

the Company's core Viking area for \$5.5 million; and (v) accelerating \$10-15 million of first quarter 2018 capital expenditures into December, 2017, with the result that Tamarack's full year 2017 capital budget was increased to \$195-198 million.

Significant Acquisitions

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

On July 12 and July 25, 2016, Tamarack closed the Penny and Redwater Acquisitions.

On June 15, 2015, Tamarack closed three separate acquisitions with three industry majors to acquire certain assets located in the greater Wilson Creek area for total aggregate cash consideration of \$55.0 million prior to adjustments (collectively, the "**Wilson Creek Cardium Acquisitions**").

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

On October 9, 2013, Tamarack closed the acquisition of Sure Energy 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.

On April 17, 2012, Tamarack closed the acquisition of private company, Echoex, for total transaction value, including the assumption of Echoex debt, of approximately \$60.5 million.

DESCRIPTION OF THE BUSINESS

Business Objectives and Strategy

Since the restructuring in 2010, Tamarack's focus has been on the acquisition and operation of resource plays in the WCSB. Tamarack is committed to long-term per share growth and its strategic direction is focused on targeting repeatable and relatively predictable "resource-like" plays that provide long-life reserves through either conventional or unconventional production methods. To support long-term sustainability, Tamarack seeks to fully fund its capital expenditure programs, and generate adjusted funds flow in excess of its required capital expenditure levels, particularly during weak commodity price environments. This strategy enables the Company to continue purchasing Common Shares for cancellation through its NCIB program and to offset future RSU dilution, with any excess adjusted funds flow earmarked for debt repayment or continued accretive tuck-in acquisitions, all of which helps to optimize per share metrics and underpin shareholder value creation. Tamarack evaluates new opportunities by following a disciplined methodology of integrating technical information with expected economic outcomes and risking the expected economic value of each opportunity according to the existing producing analogs in a particular area. The Company employs specific screening criteria to identify and evaluate prospective areas for repeatability, scope, long life and large original oil or gas-in-place per section, which usually suggests sizeable reserves. Tamarack believes that this disciplined approach has and will continue to yield more consistent results over the longer term. In addition, management of Tamarack may pursue assets and/or corporate acquisitions and may undertake divestitures of non-core assets where opportunities exist to enhance the overall value of the organization. The Company also intends to maintain its low cost and efficient structure, both in the field as well as in the general management of the business. Tamarack believes that controlling costs while maintaining cost-efficient operations and a strong balance sheet will ensure it is well positioned to manage through all commodity price cycles.

Since 2010, Tamarack has expanded and evolved from a Cardium-focused, junior E&P to an intermediate Cardium oil and Viking oil player, positioned for long-term, sustainable growth. The Company has an extensive inventory of low-risk oil development drilling locations in Alberta and Saskatchewan that are economic at a variety of oil and natural gas prices. The Viking Acquisition positioned the Company with a very high-quality asset base with low

recovery to date that is amenable to advancements in technology which can improve the recoverability of oil and economics. With this portfolio, combined with an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder return while managing its balance sheet.

Specialized Skills and Knowledge

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

Exploration Risk Management

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

Cyclical and Seasonal Impact of the Industry

The Company's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices fluctuate widely and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. Tamarack seeks to mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to support netbacks on production volumes. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Forward Contracts*" for our current hedging program.

Competitive Conditions

Tamarack actively competes for reserve acquisitions, exploration leases, licences and concessions, access to commodity markets, available capital and skilled industry personnel with a substantial number of other oil and natural 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 natural gas to these customers in the future.

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

Field equipment availability is also competitive and Tamarack continues to gain access to it through prior agreements and contacts. With continued commodity price volatility during 2019, the industry experienced stability in costs and competition for crews and equipment relative to 2018. While there was minimal impact on WCSB producers through 2019 due to increasing activity in a more favourable United States environment, the current Canadian economic environment could have longer-term impacts on the service sector capacity in the WCSB if it persists. Hiring and

retaining technical and administrative personnel continues to be a competitive process, but Tamarack rewards existing employees and provides opportunities for new staff to participate in the equity of the Company through various long-term incentive programs, which helps meet this challenge. The Company believes its distinct competitive advantage is through a combination of its scientific, integrated approach in generating drilling prospects combined with its low-cost operations and focus on per share metrics.

Employees

As at December 31, 2019, Tamarack employed 43 full time professionals, zero part-time professionals and made use of 14 consultants at its head office in Calgary, Alberta. The Company also employed 7 full time field employees located at various field offices in Alberta and Saskatchewan.

Economic Diversity

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

Change to Contracts

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

Managing Ongoing Capital Requirements

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

Environmental Policies and Responsibility

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness.

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

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

Governance and Corporate Responsibility

Tamarack has shown an ongoing commitment to sustainability with regards to the environment, business practices and stakeholder engagement. Investing in our business, our people and our community is paramount and will continue to be a guiding value at all levels of the Company. Tamarack recognizes its business model is dependent on the industry generally operating in a responsible fashion and it is committed to conducting its business in an economically, socially and environmentally sustainable and responsible manner.

Across all facets of its business, Tamarack clearly demonstrates a commitment to sustainability. Investing in long-term projects is expected to ultimately decrease production decline rates, increase sustainability and help drive improved returns.

Relationships with all stakeholders are approached with integrity and respect, and Tamarack takes care to select operators that share its core values. The Company's lands are developed ethically and responsibly. A more detailed description of Tamarack's corporate reporting initiatives and a discussion of environmental, social and governance (ESG) issues, will be outlined in the Company's 2020 Corporate Profile, which will be filed on the Company's website at www.tamarackvalley.ca and on SEDAR but is not to be considered part of this AIF.

Tamarack has adopted policies relating to its business conduct, including a business code of conduct, a whistleblower policy, a policy concerning confidentiality, fair disclosure and trading in restricted securities, a respectful workplace policy, and a health, safety and environment policy. Additional information relating to these and other policies can be found on the Company's website at www.tamarackvalley.ca.

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 January 31, 2020. The effective date of the Statement is December 31, 2019 and the preparation date of the Statement is January 27, 2020. In compliance with the requirements of NI 51-101, tables below provide the reserves disclosure for Tamarack as at December 31, 2019, independently evaluated by GLJ. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Tamarack believes is important to the readers of this information.

Disclosure of Reserves Data

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

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and conventional natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, NGLs and conventional natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL and conventional natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers

at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

The following tables set forth certain information relating to the Company's oil, natural gas and NGL reserves as well as the net present value of the estimated Future Net Revenue associated with such reserves as at December 31, 2019 contained in the GLJ Report. These tables summarize the data contained in the GLJ Report, and, as a result, may contain slightly different numbers than the GLJ Report due to rounding.

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

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS

Reserves Category	Crude Oil Lt. & Med. Gross ⁽¹⁾ (MBbl)	Crude Oil Lt. & Med. Net ⁽¹⁾ (MBbl)	Crude Oil Heavy Gross (MBbl)	Crude Oil Heavy Net (MBbl)	Natural Gas Gross (MMcf) ⁽²⁾	Natural Gas Net (MMcf) ⁽²⁾	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gross (MBoe)	Total Net (MBoe)
Proved:										
Developed Producing	17,400	15,337	25	22	82,976	76,043	3,170	2,616	34,424	30,649
Developed Non-Producing	1,846	1,312	160	134	2,805	2,560	39	35	2,513	1,908
Undeveloped	13,497	11,693	170	133	36,979	34,441	1,119	1,001	20,949	18,566
Total Proved	32,743	28,342	355	289	122,759	113,044	4,328	3,651	57,886	51,123
Probable	26,945	22,636	358	274	82,223	75,838	2,739	2,326	43,746	37,876
Total Proved plus Probable	59,688	50,978	713	563	204,982	188,882	7,067	5,977	101,632	88,999

Notes:

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

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES AS OF DECEMBER 31, 2019
DISCOUNTED AT % PER YEAR⁽²⁾⁽³⁾
FORECAST PRICES AND COSTS

Reserves Category	0% (\$000)	5% (\$000)	10% (\$000)	15% (\$000)	20% (\$000)	Unit Value	Unit Value
						Before Tax	Before Tax
						Discounted	Discounted
						at	at
						10%/Year ⁽¹⁾	10%/Year ⁽¹⁾
						(\$/Boe)	(\$/Mcfe)
Proved:							
Developed Producing	768,457	651,261	570,656	511,351	465,628	18.62	3.10
Developed Non-Producing	80,674	65,601	55,226	47,547	41,611	28.95	4.82
Undeveloped	401,536	298,791	226,398	174,336	135,824	12.19	2.03
Total Proved	1,250,666	1,015,654	852,280	733,234	643,063	16.67	2.78
Probable	1,273,554	860,135	624,135	477,074	379,016	16.48	2.75
Total Proved plus Probable	2,524,220	1,875,788	1,476,415	1,210,308	1,022,079	16.59	2.76

Notes:

- (1) Unit values are based on Company net reserves.
- (2) It should be noted that the estimated net present values are based on a certain set of assumptions and estimates including those for timing of future capital expenditures, deductibility of tax pools, and applicability of special tax incentives. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein.
- (3) The prices used to estimate net present values are the average of those used by the largest independent industry reserve evaluators.
- (4) Columns may not add due to rounding.

**NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES AS
OF DECEMBER 31, 2019 DISCOUNTED AT (%/YEAR)⁽²⁾⁽³⁾**

FORECAST PRICES AND COSTS

Reserves Category	0% (\$000)	5% (\$000)	10% (\$000)	15% (\$000)	20% (\$000)	Unit Value	Unit Value
						After Tax	After Tax
						Discounted	Discounted
						at	at
						10%/Year ⁽¹⁾	10%/Year ⁽¹⁾
						(\$/Boe)	(\$/Mcfe)
Proved:							
Developed Producing	768,457	651,261	570,656	511,351	465,628	18.62	3.10
Developed Non-Producing	64,913	53,871	46,317	40,660	36,203	24.28	4.05
Undeveloped	308,878	223,129	163,333	120,884	89,885	8.80	1.47
Total Proved	1,142,248	928,261	780,307	672,895	591,715	15.26	2.54
Probable	977,109	653,272	469,315	355,390	279,910	12.39	2.07
Total Proved plus Probable	2,119,357	1,581,532	1,249,622	1,028,285	871,625	14.04	2.34

Notes:

- (1) Unit values are based on Company net reserves.
- (2) It should be noted that the estimated net present values are based on a certain set of assumptions and estimates including those for timing of future capital expenditures, deductibility of tax pools, and applicability of special tax incentives. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein.
- (3) The prices used to estimate net present values are the average of those used by the largest independent industry reserve evaluators.
- (4) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2019

FORECAST PRICES AND COSTS

Reserves Category	Revenue (\$000)	Royalties (\$000)	Operating Costs (\$000)	Capital Development Costs (\$000)	Abandonment & Reclamation Costs (\$000)	Future	Future
						Net	Net
						Revenue	Revenue
						Before	After
						Income	Income
						Tax (\$000)	Tax (\$000)
Total Proved	3,233,947	416,914	1,016,866	398,535	150,966	1,250,666	1,142,248
Total Proved plus Probable	6,061,529	841,250	1,801,739	702,724	191,597	2,524,220	2,119,357

FUTURE NET REVENUE BY PRODUCTION TYPE AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

Reserve Category	Production Type	Net Revenue Before Income Taxes @ 10% DCF (\$000)	Unit Value ⁽⁴⁾ (\$/Boe)	Unit Value ⁽⁴⁾ (\$/Mcfe)
Total Proved	Light and Medium Oil ⁽¹⁾⁽²⁾	815,947	18.95	3.16
	Heavy Oil ⁽¹⁾	4,885	13.94	2.32
	Conventional Natural Gas ⁽³⁾	32,108	4.19	0.70
	Coal Bed Methane	(661)	(16.30)	(2.72)
	Total	852,280	16.67	2.78
Proved plus Probable	Light and Medium Oil ⁽¹⁾⁽²⁾	1,409,680	18.62	3.10
	Heavy Oil ⁽¹⁾	11,623	17.25	2.88
	Conventional Natural Gas ⁽³⁾	55,723	4.43	0.74
	Coal Bed Methane	(610)	(10.85)	(1.81)
	Total	1,476,415	16.59	2.76

Notes:

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

Definitions and Additional Notes to Reserves Data Tables

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

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

"Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

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

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

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

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

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

- (a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- (b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- (c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

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

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

- (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 natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

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

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling, completing and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

“exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

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

“gross” means:

- (a) in relation to the Company’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- (b) in relation to wells, the total number of wells in which the Company has an interest; and
- (c) in relation to properties, the total area of properties in which the Company has an interest.

“net” means

- (a) in relation to the Company’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
- (b) in relation to the Company’s interest in wells, the number of wells obtained by aggregating the Company’s working interest in each of its gross wells; and
- (c) in relation to the Company’s interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

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

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

Pricing Assumptions

The following tables detail the reference prices and inflation rate assumptions as at December 31, 2019 utilized by GLJ in the GLJ Report for estimating reserves data. GLJ is an independent qualified reserves evaluator. The information included in the summary table below is based on an average of pricing assumptions prepared by three independent external reserves evaluators.

Tamarack’s weighted average realized sales prices for the year ended December 31, 2019 were \$66.25/Bbl for light and medium crude oil, \$55.27/Bbl for heavy oil, \$25.57/Bbl for NGL and \$2.06/Mcf for natural gas. The average realized price on a total oil equivalent basis was \$43.37/Boe.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2019

FORECAST PRICES AND COSTS

Year	Crude Oil WTI Cushing Oklahoma (US\$/Bbl)	Crude Oil Edmonton Par Price 40° API (C\$/Bbl)	Crude Oil Hardisty Bow River 25° API (C\$/Bbl)	Crude Oil Hardisty Heavy 12° API (C\$/Bbl)	Natural Gas AECO/NIT Spot ⁽¹⁾ (C\$/Mmbtu)	NGL Edmonton Propane (C\$/Bbl)	NGL Edmonton Butane (C\$/Bbl)	NGL Edm. C5+ (C\$/Bbl)	Inflation Rate (%/Year)	Exchange Rate (US\$/C\$)
Forecast										
2020	61.00	72.64	58.43	51.23	2.04	26.36	42.09	76.83	0.00	0.7600
2021	63.75	76.06	63.00	56.11	2.32	29.80	47.03	79.82	1.70	0.7700
2022	66.18	78.35	64.99	57.72	2.62	32.94	50.66	82.30	2.00	0.7850
2023	67.91	80.71	66.91	59.45	2.71	34.00	52.21	84.72	2.00	0.7850
2024	69.48	82.64	68.65	61.09	2.81	34.89	53.48	86.71	2.00	0.7850
2025	71.07	84.60	70.41	62.75	2.89	35.78	54.77	88.73	2.00	0.7850
2026	72.68	86.57	72.20	64.43	2.96	36.69	56.07	90.77	2.00	0.7850
2027	74.24	88.49	73.91	66.04	3.03	37.57	57.32	92.76	2.00	0.7850
2028	75.73	90.31	75.53	67.55	3.10	38.41	58.50	94.65	2.00	0.7850
2029	77.24	92.17	77.17	69.08	3.17	39.26	59.71	96.57	2.00	0.7850
2030	78.79	94.01	78.72	70.47	3.24	40.11	60.90	98.53	2.00	0.7850
2031	80.36	95.89	80.29	71.87	3.30	40.91	62.12	100.50	2.00	0.7850
2032	81.97	97.81	81.90	73.31	3.37	41.73	63.36	102.51	2.00	0.7850
2033	83.61	99.76	83.54	74.78	3.43	42.56	64.63	104.56	2.00	0.7850
2034	85.28	101.76	85.21	76.27	3.50	43.42	65.92	106.65	2.00	0.7850
2035+ ⁽²⁾	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.00	0.7850

Notes:

- (1) AECO spot refers to the same-day spot price averaged over the period.
- (2) +2.0%/year thereafter

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, 2019 against such Reserves as at December 31, 2018 based on forecast price and cost assumptions:

RECONCILIATION OF COMPANY GROSS RESERVES⁽¹⁾ BY PRINCIPAL PRODUCTION TYPE FORECAST PRICES AND COSTS

	Lt & Med Crude Oil Proved ⁽²⁾ (Mbbbl)	Lt & Med Crude Oil Probable ⁽²⁾ (Mbbbl)	Lt & Med Crude Oil Proved + Probable ⁽²⁾ (Mbbbl)	Heavy Crude Oil Proved (MBbl)	Heavy Crude Oil Probable (MBbl)	Heavy Crude Oil Proved + Probable (MBbl)	Total Crude Oil Proved (MBbl)	Total Crude Oil Probable (MBbl)	Total Crude Oil Proved + Probable (MBbl)
December 31, 2018	29,993	28,158	58,152	549	450	999	30,542	28,608	59,151
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery ⁽³⁾	8,756	176	8,932	-	-	-	8,756	176	8,932
Technical Revisions	(1,221)	(1,197)	(2,418)	(28)	(92)	(120)	(1,248)	(1,290)	(2,538)
Acquisitions	150	49	198	-	-	-	150	49	198
Dispositions	(61)	(90)	(151)	-	-	-	(61)	(90)	(151)
Economic Factors	(92)	(151)	(242)	(5)	-	(5)	(96)	(151)	(247)
Production	(4,783)	-	(4,783)	(161)	-	(161)	(4,943)	-	(4,943)
December 31, 2019	32,743	26,945	59,688	355	358	713	33,098	27,303	60,401

	NGL Proved (MBbl)	NGL Probable (MBbl)	NGL Proved + Probable (MBbl)	Natural Gas Proved ⁽⁴⁾ (MMcf)	Natural Gas Probable ⁽⁴⁾ (MMcf)	Natural Gas Proved + Probable ⁽⁴⁾ (MMcf)	Total Proved (MBoe)	Total Probable (MBoe)	Total Proved + Probable (MBoe)
December 31, 2018	4,249	2,824	7,073	125,163	86,930	212,093	55,651	45,921	101,572
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery ⁽³⁾	265	93	358	11,112	3,559	14,672	10,874	862	11,736
Technical Revisions	428	(118)	310	6,634	(7,293)	(659)	285	(2,623)	(2,338)
Acquisitions	7	2	10	653	215	868	266	87	353
Dispositions	(1)	(1)	(2)	(37)	(17)	(54)	(69)	(94)	(162)
Economic Factors	(28)	(62)	(90)	(1,259)	(1,171)	(2,430)	(334)	(408)	(742)
Production	(592)	-	(592)	(19,507)	-	(19,507)	(8,786)	-	(8,786)
December 31, 2019	4,328	2,739	7,067	122,759	82,223	204,982	57,886	43,746	101,632

Notes:

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

Proved Undeveloped Reserves are generally those reserves related to drilling spacing units directly offsetting 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, Tamarack has a clearly stated strategy to fully fund its capital expenditures with internally-generated adjusted funds flow. The Company expects to spend approximately 62% of its total Proved future development capital ("FDC") and 46% of total Proved plus Probable FDC in 2020 and 2021. In 2022, 27% of the Company's total Proved FDC is expected to be invested, with approximately 11% remaining to be invested in the subsequent two years, while 24% of total Proved plus Probable FDC is expected to be spent in 2022 with approximately 30% remaining to be invested in the following two years. Tamarack forecasts that 99% of the FDC forecast by GJL will be invested within five years. The Company believes its allocation of capital investment and associated development of reserves is reasonable, ensures conservative debt levels, and is consistent with historical practices.

Year	Crude Oil Lt. & Med. First Attributed ⁽¹⁾⁽²⁾ (MMbbl)	Crude Oil Lt. & Med. at Year- End ⁽²⁾ (MMbbl)	Crude Oil Heavy First Attributed ⁽¹⁾ (MMbbl)	Crude Oil Heavy at Year-End (MMbbl)	Natural Gas First Attributed ⁽¹⁾⁽³⁾ (MMcf)	Natural Gas at Year- End ⁽³⁾ (MMcf)	Natural Gas Liquids First Attributed ⁽¹⁾ (MMbbl)	Natural Gas Liquids at Year-End (MMbbl)	Total First Attributed ⁽¹⁾ (MBoe)	Total at Year-End (MBoe)
2017	5,746	10,382	182	243	16,803	38,729	618	1,396	9,347	18,475
2018	3,433	12,813	-	163	7,172	40,281	208	1,543	4,837	21,233
2019	4,567	13,497	-	170	3,842	36,979	73	1,119	5,280	20,949

Notes:

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

Probable Undeveloped Reserves

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

Year	Crude Oil Lt. & Med. First Attributed ⁽¹⁾⁽²⁾ (MBbl)	Crude Oil Lt. & Med. at Year-End ⁽²⁾ (MBbl)	Crude Oil Heavy First Attributed ⁽¹⁾ (MBbl)	Crude Oil Heavy at Year-End (MBbl)	Natural Gas First Attributed ⁽¹⁾⁽³⁾ (MMcf)	Natural Gas at Year-End ⁽³⁾ (MMcf)	Natural Gas Liquids First Attributed ⁽¹⁾ (MBbl)	Natural Gas Liquids at Year-End (MBbl)	Total First Attributed ⁽¹⁾ (MBoe)	Total at Year-End (MBoe)
2017	9,462	16,659	234	444	24,503	55,351	649	1,816	14,428	28,143
2018	7,886	21,944	-	274	6,968	56,544	191	1,869	9,239	33,511
2019	4,856	18,718	-	278	2,958	51,703	54	1,648	5,403	29,261

Notes:

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

Significant Factors or Uncertainties Affecting Reserves Data

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

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

Tamarack does not anticipate any significant economic factors or significant uncertainties will affect any particular components of its reserves data. However, the Company's reserves can be affected significantly by fluctuations in commodity product pricing, capital expenditures, operating costs, royalty regimes and other government restrictions and well performance that are beyond its control. See "Risk Factors" for further details. See Note 10 of the Company's Consolidated Financial Statements for the years ended December 31, 2019 and 2018 for our decommissioning obligations. Provisions for the abandonment and reclamation of all of the Company's existing and future wells to a standard imposed by applicable government or regulatory authorities have been included (this includes all active entities within active assets only); all other abandonment and reclamation costs have not been included; it is noted that this is acceptable disclosure within NI 51-101 but does not meet the minimum recommendations within the COGE Handbook.

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 natural gas prices and reservoir performance. Such revision can be either positive or negative.

Future Development Costs

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

FUTURE DEVELOPMENT COSTS (\$000)⁽¹⁾
FORECAST PRICES AND COSTS

Year	Total Proved Reserves (\$000)	Total Proved Plus Probable Reserves (\$000)
2020	111,109	157,211
2021	138,448	166,499
2022	106,580	169,691
2023	32,747	110,363
2024	648	89,950
2025	108	108
2026	8,640	8,640
2027	181	0
2028	0	0
2029	0	188
2030	0	0
2031	0	0
Subtotal	398,462	702,650
Remainder	74	74
Total	398,535	702,724
10% Discounted	338,673	570,433

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.

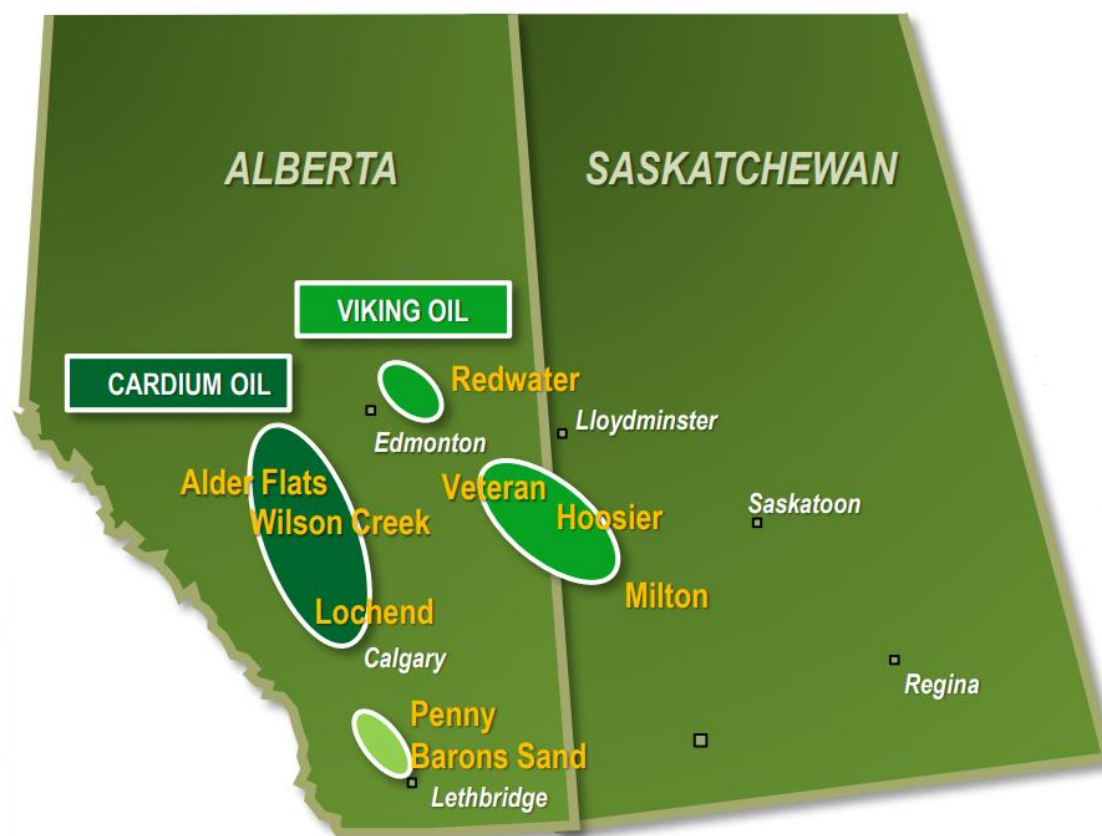
Tamarack typically has three sources of funding available to finance its capital expenditure program: internally generated adjusted funds flow, debt financing when appropriate and new equity issues, if available on favourable terms.

The Company expects to fully fund its 2020 capital program with internally generated adjusted funds flow and the program has been structured to maintain balance sheet strength. Management does not anticipate any costs of funding will materially affect Tamarack's disclosed reserves and future net revenues nor make the development of any of its properties uneconomic.

Other Oil and Natural Gas Information

The following is a description of Tamarack's principal oil and natural gas properties that are on production or under development as at March 4, 2020. Information in respect of current production is average production, net to its working interest, except where otherwise indicated. Reserves noted are company interest reserves which include both working interest and royalty interest values.

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



Tamarack's oil and natural gas properties are all onshore and primarily located in the provinces of Alberta and Saskatchewan largely targeting the Cardium oil and Viking oil plays. A summary of the important oil and natural gas properties by area as at December 31, 2019 follows. Tamarack's producing and non-producing wells by area together with the working interest are contained in a table following these property descriptions. A summary of the Company's booked and unbooked drilling inventory can be found in the "Oil and Gas Measures" section found on page 84 of this AIF.

Viking Light Oil:

Viking Areas – Veteran/Consort/Esther, AB

Tamarack has interests in 365.7 (342.4 net) sections of land in the Veteran and Consort areas of southeast Alberta. Proved Developed Producing Reserves of 8,169 mboe were booked to 401 (388.3 net) producing wells. Total Proved plus Probable Reserves of 32,432 mboe were also assigned to the area. Proved undeveloped drilling locations total 170 (165.6 net). Tamarack's total estimated horizontal drilling inventory is approximately 270 (264.0 net) Viking oil locations under primary recovery and an additional 900 (900.0 net) Viking oil equivalent locations under a waterflood scenario. Throughout 2019, Tamarack invested in the Veteran area infrastructure, including water handling facilities for the waterflood project. The Company also completed several Viking oil "tuck-in"

acquisitions, including a small swap, in the Veteran/Consort area of Alberta for net cash proceeds of \$8.9 million and land swap of 1.6 net sections, resulting in the addition of 160 boe/d and 21.0 net sections of undeveloped Viking lands to Tamarack's portfolio.

From 2017 to the end of 2019, Tamarack invested approximately \$54 million in capital for the Veteran waterflood project including pipelines, water handling facilities and injection facilities. In addition, Tamarack has drilled 20 current injection wells, 14 wells for future conversion to injection wells and 4 water source wells. As at year-end 2019, the first two patterns in the Hamilton Lake project area (1.5 sections) were contributing incremental production of 350 boe/d. Of the reserves booked to the Veteran and Consort areas, 851 mboe Proved Developed Producing and 8,897 mboe total Proved plus Probable were attributable to the waterflood.

Tamarack operates a 7,000 bbl/d pipeline connected oil processing facility at Veteran, AB in addition to two gas processing facilities – a 34.2% working interest 8 mmcf/d gas plant in Consort, AB and a 100% working interest 5.5 mmcf/d gas plant in Veteran, AB.

Viking Areas – North Hoosier/Milton/Coleville, SK

Tamarack has interests in 173.2 (146.6 net) sections of land in the North Hoosier, Milton and Coleville areas of southwest Saskatchewan. Total Proved Developed Producing Reserves of 4,853 mboe were booked to 236 (165.4 net) producing wells. Proved plus Probable Reserves of 11,529 mboe were also assigned to the area. Proved undeveloped drilling locations total 39 (36.2 net). Tamarack's total estimated horizontal drilling inventory is approximately 116 (108.2 net) Viking oil locations. Tamarack also owns and operates significant oil and gas pipeline infrastructure, multiple batteries and compressors in the area. The area gas infrastructure has enabled Tamarack to conserve solution gas.

Viking Area – Redwater, AB

Tamarack has interests in 74 (66.3 net) sections of land in the Redwater area of Alberta. Proved Developed Producing Reserves of 1,365 mboe were booked to 155 (143.9 net) producing wells. Total Proved plus Probable Reserves of 7,518 mboe were also assigned to the area and proved undeveloped drilling locations of 63 (59.5 net) were included in the evaluation. Tamarack's total estimated drilling inventory is approximately 114 (107.5 net) horizontal Viking oil locations and 32 (29.3 net) horizontal Ellerslie oil locations. Tamarack processes all area production through operated facilities including a 10,000 bbls/d emulsion processing oil battery.

Alberta Cardium Light Oil:

Wilson Creek/Alder Flats/Pembina

Tamarack has interests in 310.5 (245.0 net) sections of land in the Wilson Creek/Alder Flats/Pembina area of Alberta. At year-end 2019, the Company had proved developed producing reserves of 13,061 mboe that were booked to 217 (192.4 net) producing Cardium and 76 (48.8 net) wells producing from other zones including a 52% interest in the Pekisko Gas Unit. Total proved plus probable reserves of 35,537 mboe were also assigned to the area. Proved undeveloped drilling locations of 50 (42.5 net) were included in the evaluation. Tamarack's total estimated horizontal drilling inventory is approximately 176 (142.5 net) Cardium oil locations (239.8 net 1-mile equivalents) and 10 (7.0 net) Manville natural gas locations. Tamarack operates: two 100% owned pipeline-connected oil batteries – one with oil capacity of 7,000 bbl/d and the other with 1,000 bbl/d – a 52% owned 30 mmcf/d gas plant and 100% ownership in a 13 mmcf/d gas plant including vast gathering infrastructure which enables interconnectivity and utilization flexibility within our own infrastructure. The two operated oil batteries are pipeline-connected to the Pembina Pipeline.

Garrington/Lochend

Tamarack has interests in 14.5 (8.7 net) sections of land in the Garrington and Lochend areas of Alberta. At year-end 2019, proved developed producing reserves of 648 mboe were booked 24 (14.1 net) producing wells. Proved plus Probable Reserves of 1,519 mboe were also assigned to the area. No proved undeveloped drilling locations were included in the evaluation.

Lethbridge Light Oil:Barons and Banff Light Oil - Penny Area

Tamarack has interests in 268.4 (256.5 net) sections of land in the Penny area of Southern Alberta featuring a large Barons light oil pool under active waterflood with only approximately 14% recovered to end of year 2019, as well as a Banff light oil pool. Proved Developed Producing Reserves of 4,294 mboe were booked to 68 (68.0 net) producing wells. Proved plus Probable Reserves of 8,870 mboe were also booked to the area. 7 (7.0 net) Barons proved undeveloped along with 5 (5.0 net) Barons and 5 (5.0 net) Banff probable undeveloped locations were included in the evaluation. Tamarack's estimated horizontal drilling inventory includes approximately 12 (12.0 net) Barons oil locations and 19 (15.0 net) Banff oil locations. Key infrastructure consists of four 100% owned oil batteries with combined emulsion processing capacity of over 6,000 bbls/d, two 100% owned gas plants with combined 12.5 mmcf/d capacity, multiple injectors and various field compression equipment.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which the Company had a working interest⁽¹⁾ as at December 31, 2019.

Area	Crude Oil Producing (Gross)	Crude Oil Producing (Net)	Crude Oil Non-prod (Gross)	Crude Oil Non-prod (Net)	Natural Gas Producing (Gross)	Natural Gas Producing (Net)	Natural Gas Non-prod (Gross)	Natural Gas Non- prod (Net)
Cardium Oil Areas	295.0	258.2	77.0	63.1	127.0	80.0	72.0	43.9
Viking Oil Areas	882.0	811.4	266.0	247.9	124.0	101.4	207.0	181.5
Penny Oil Area	96.0	93.8	34.0	32.4	263.0	136.9	91.0	77.1
Heavy Oil Area	31.0	31.0	11.0	10.7	11.0	10.0	15.0	14.5
Other	12.0	5.1	10.0	9.1	347.0	319.2	114.0	93.7
Total	1316.0	1199.5	398.0	363.2	872.0	647.5	499.0	410.7

Notes:

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

Developed and Undeveloped Lands

Province	Undeveloped Acres (Gross)	Undeveloped Acres (Net)	Developed Acres (Gross)	Developed Acres (Net)	Total Acres (Gross)	Total Acres (Net)
Alberta	521,150	456,983	485,382	397,634	1,006,532	854,617
Saskatchewan	40,573	39,457	124,027	107,168	164,600	146,626
Total	561,723	496,441	609,410	504,802	1,171,132	1,001,243

Tamarack had 561,723 gross acres (227,321 gross hectares) and 496,441 net acres (200,903 net hectares) of undeveloped land as at December 31, 2019 located in Alberta and Saskatchewan. The Company has no work commitments currently scheduled on these lands. Tamarack has leases on 53,879 gross (53,879 net) acres that expire in 2020. Some of these leases may be extended at the discretion of the leaseholder. The Company reviews the economic viability of these undeveloped properties on the basis of pricing and capital availability and allocation. There is no guarantee that commercial reserves will be discovered or developed on these properties.

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

Forward Contracts

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

A list of the Company's derivative financial instruments as at December 31, 2019 can be found in note 5(d) of the Notes to the Consolidated Financial Statements for the years ended December 31, 2019 and 2018.

Tax Horizon

Tamarack was not required to pay income taxes during the year ended December 31, 2019. Based on a strategy of reinvesting all internally generated cash flow in an exploration and development program and based on the commodity prices used in the GLJ Report, Tamarack estimates that it will not be required to pay income taxes until sometime after 2023.

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, 2019.

Expenditures for the Year Ended December 31, 2019	Amount (\$'000)
Property acquisition costs – Unproved properties ⁽¹⁾	1,603
Property acquisition costs – Proved properties ⁽²⁾	9,942
Corporate acquisition costs	-
Exploration costs ⁽³⁾	198
Development costs ⁽⁴⁾⁽⁵⁾	176,755
Other	410
Total	188,908

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, 2019.

Type of Well	Development Wells (Gross)	Development Wells (Net)
Light and Medium Oil	143.0	138.6
Heavy Oil	0.0	0.0
Natural Gas	0.0	0.0
Service	6.0	5.9
Dry and Abandoned	0.0	0.0
Stratigraphic Test	0.0	0.0
Total	149.0	144.5

In 2020, and contingent on commodity price levels and associated well economics, the Company expects to drill between 90 to 100 net wells, including 80 to 90 Viking light oil wells, seven to nine Cardium light oil wells and two to five wells at Penny targeting the Lower Mississippian development. In addition, the 2020 budget includes approximately \$50 to \$58 million of planned waterflood investment which is expected to include 14 to 16 well conversions in 2020 and the drilling of 15 to 20 additional injection wells in East Veteran. The Company will continue to focus on drilling wells that will generate the highest rates of return. See "General Development of the Business – Recent Developments".

Finding, Development and Acquisition Costs

The following table summarizes Tamarack's finding and development ("F&D") and finding, development and acquisition ("FD&A") costs for the periods indicated.

(\$/Boe) ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾	2019	2018	2017	3-Year Average
Proved Reserves				
Finding, development and acquisition cost	18.68	18.83	27.86	23.49
Finding and development costs	18.10	20.23	20.70	19.70
Acquisition costs	50.57	4.33	33.33	31.48
Proved plus Probable Reserves				
Finding, development and acquisition cost	21.64	11.85	20.91	18.55
Finding and development costs	20.97	12.59	17.88	16.40
Acquisition costs	52.13	4.12	23.15	22.16

Notes:

- (1) FD&A costs are calculated by dividing total capital by reserve additions during the applicable period. Total capital includes both capital expenditures incurred and changes in future development capital required to bring Proved undeveloped Reserves and Probable Reserves to production during the applicable period. Reserve additions is calculated as the change in reserves from the beginning to the end of the applicable period excluding production.
- (2) Including changes in future development capital expenditures.
- (3) While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of F&D costs, FD&A costs have been presented because acquisitions and dispositions can have a significant impact on the Company's ongoing reserve replacement costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. F&D costs both including and excluding acquisitions and dispositions have been presented above.
- (4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total F&D costs related to reserves additions for that year.
- (5) F&D costs are not necessarily calculated in the same manner by all issuers. Accordingly, they should not be used to make comparisons amongst different issuers. See "Conventions".

Production Estimates

The following table sets out the first-year production forecast of volumes of Tamarack's working interest (Company Gross) production for each product type estimated by GLJ for the year ended December 31, 2019, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "Disclosures of Reserves Data".

	Gross Lt. & Med. Crude Oil ⁽¹⁾ (bbl/d)	Gross Heavy Crude Oil (bbl/d)	Gross Conventional Natural Gas ⁽²⁾ (Mcf/d)	Gross Natural Gas Liquids (bbl/d)	Gross Barrel of Oil Equivalent (boe/d)
Total Proved					
Alder/Wilson	2,166	-	22,058	953	6,795
Consort/Veteran	7,895	-	9,144	99	9,518
Other Properties	3,450	93	16,034	491	6,706
Total	13,511	93	47,236	1,543	23,020
Total Proved plus Probable					
Alder/Wilson	2,284	-	23,254	1,000	7,160
Consort/Veteran	9,518	-	10,038	109	11,300
Other Properties	4,703	102	17,667	538	8,287
Total	16,505	102	50,959	1,647	26,746

Notes:

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

2019 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2019, Tamarack's share of average daily production volume, prior to royalties, the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

	3 Months Ended Mar 31/19	3 Months Ended Jun 30/19	3 Months Ended Sep 30/19	3 Months Ended Dec 31/19	12 Months Ended Dec 31/19
Average Daily Production ⁽¹⁾					
Light and Medium Oil (Bbl/d)	12,689	13,237	12,748	13,729	13,103
Heavy Oil (Bbl/d)	483	521	440	318	440
Natural Gas (Mcf/d)	50,576	53,451	55,224	54,462	53,444
NGLs (Bbl/d)	1,548	1,423	1,779	1,735	1,622
Total (Boe/d)	23,149	24,090	24,171	24,859	24,072
Average Net Production Prices Received					
Light and Medium Oil (\$/Bbl)	65.47	70.17	65.10	64.26	66.25
Heavy Oil (\$/Bbl)	40.65	65.14	56.74	58.96	55.27
Natural Gas (\$/Mcf)	2.82	1.71	1.54	2.26	2.06
NGLs (\$/Bbl)	40.85	21.81	19.08	21.96	25.57
Total (\$/Boe)	45.62	45.04	40.28	42.72	43.37
Royalties Paid					
Light and Medium Oil (\$/Bbl)	7.06	6.73	7.44	7.31	7.14
Heavy Oil (\$/Bbl)	5.58	11.47	9.59	7.02	8.63
Natural Gas (\$/Mcf)	0.19	0.09	0.03	0.10	0.10
NGLs (\$/Bbl)	6.50	2.09	2.99	0.47	2.94
Total (\$/Boe)	4.86	4.20	4.36	4.39	4.45
Production Costs ⁽²⁾⁽³⁾⁽⁴⁾					
Light and Medium Oil (\$/Boe)	9.75	9.41	9.11	9.78	9.51
Heavy Oil (\$/Boe)	43.61	39.17	40.05	39.50	40.89
Natural Gas (\$/Mcfe)	1.89	2.84	2.93	1.68	2.35
NGLs (\$/Boe)	0.00	0.00	0.00	0.00	0.00
Total (\$/Boe)	10.20	10.12	9.87	9.96	10.03
Netback Received					
Light and Medium Oil (\$/Bbl)	48.67	54.02	48.56	47.16	49.60
Heavy Oil (\$/Bbl)	-8.54	14.51	7.10	12.44	5.75
Natural Gas (\$/Mcf)	0.74	-1.22	-1.42	0.48	-0.40
NGLs (\$/Bbl)	34.35	19.72	16.09	21.49	22.63
Total (\$/Boe)	30.56	30.72	26.06	28.37	28.89

Notes:

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

The following table sets forth the average daily production volumes for the year ended December 31, 2019 for each of the important properties comprising Tamarack's assets.

Property	Crude Oil Lt & Med (Bbl/d)	Crude Oil Heavy (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Total (Boe/d)
Cardium Oil Area	3,232	8	25,405	1,118	8,593
Viking Oil Area	8,569	339	19,708	462	12,654
Penny Oil Area	1,231	-	2,087	24	1,603
Heavy oil Area	55	93	180	-	178
Other	15	-	6,064	18	1,043
Total	13,102	440	53,444	1,622	24,071

DESCRIPTION OF SHARE CAPITAL

Tamarack is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As at March 4, 2020, there are 222,295,253 Common Shares and no preferred shares issued and outstanding, with 302,884 of the outstanding Common Shares held in treasury. The following is a summary of the rights, privileges, restrictions and conditions attached to such securities.

Common Shares

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

Preferred Shares, Issuable in Series

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

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the trading symbol "TVE". The following table sets forth the market price ranges and the trading volumes of the Common Shares for the financial year ended December 31, 2019 and as at March 4, 2020:

Month	High (\$)	Low (\$)	Volume
January, 2019	2.61	2.05	27,721,907
February, 2019	2.96	2.03	16,580,239
March, 2019	2.88	2.36	20,561,646
April, 2019	3.09	2.35	22,488,123
May, 2019	2.75	2.12	17,020,446
June, 2019	2.36	1.85	12,689,384
July, 2019	2.21	1.79	10,765,457
August, 2019	2.14	1.66	8,209,197
September, 2019	2.44	1.82	8,844,975
October, 2019	2.04	1.61	7,662,413
November, 2019	1.96	1.59	15,683,402
December, 2019	2.05	1.72	11,757,438
January, 2020	2.27	1.66	15,699,817
February, 2020	1.77	1.04	18,897,423
March 1 – 4, 2020	1.36	1.24	870,877

Prior Sales

During the financial year ended December 31, 2019, the Company granted an aggregate of 390,000 options, each option entitling the holder thereof to acquire one Common Share, the particulars of which are set forth in the following table:

Date of Option Grant	Number	Exercise Price (\$)
March 15, 2019	390,000	\$2.57
Total Issued:	390,000	\$2.57

Notes:

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

During 2019, a total of 15,000 options were exercised, and 1,126,500 options expired or were forfeited.

Except as set forth below, no additional unlisted securities of the Company were issued during the financial year ended December 31, 2019.

RSU Grants

In the year ended December 31, 2019, the Company granted 2,532,053 RSUs pursuant to the PRSU Plan. During 2019, 2,568,161 RSUs were exercised. As of December 31, 2019, there were 6,986,921 RSUs outstanding. Each RSU entitles the holder thereof upon settlement to receive one Common Share in accordance with the PRSU Plan. An RSU holder may also elect to have RSUs settled in exchange for a payment by the Company of a cash amount per RSU equal to the closing price of the Common Shares before the distribution date for the settlement of the RSUs, provided; however, that the Company has the sole discretion to consent or refuse the election to receive cash. The RSU grants vest one-third on the first, second and third anniversary of the date of grant.

Date of RSU Grant	Number	Exercise Price (\$)
January 1, 2019	40,000	\$2.33
March 15, 2019	2,256,613	\$2.57
April 2, 2019	7,500	\$2.49
April 15, 2019	40,000	\$2.80
April 17, 2019	37,000	\$2.86
April 29, 2019	45,000	\$2.82
May 1, 2019	10,000	\$2.59
June 10, 2019	30,000	\$2.09
June 18, 2019	34,000	\$2.08
November 5, 2019	31,940	\$1.93
Total Issued:	2,532,053	\$2.56

PSU Grants

In the year ended December 31, 2019, the Company granted 1,210,880 PSUs pursuant to the PRSU Plan. As of December 31, 2019, there were 2,156,980 PSUs outstanding, with 263,525 PSUs earned and no PSUs exercisable. PSUs are earned over a three-year period based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. Each PSU entitles the holder to an award value on the third anniversary of the date of grant, if previously earned, multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on the aforementioned targets. A PSU holder may also elect to have PSUs settled in exchange for a payment by the Company of a cash amount per PSU equal to the closing price of the Common Shares before the distribution date for the settlement of the PSUs, provided; however, that the Company has the sole discretion to consent or refuse the election to receive cash.

Date of PSU Grant	Number	Exercise Price (\$)
March 15, 2019	1,210,880	\$2.57
Total Issued:	1,210,880	\$2.57

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 TAC Preferred Shares. Under the terms and conditions of the Exchange Agreement, the Company has the option to purchase each TAC Preferred Share for either a cash payment reflecting the "in-the-money" amount or equivalent Common Share consideration under certain circumstances including (a) the occurrence of a "change of control" of Tamarack (as defined in Tamarack's option plan), (b) the holder ceasing to act as a director, officer, employee or consultant of Tamarack for any reason other than death or permanent disability, (c) the death or disability of the holder of TAC Preferred Shares, and (d) the Common Shares trading at a 300% premium to the exercise price of \$3.12 per Common Share equivalent over any consecutive 20 day trading period (being days on which at least a board lot of Common Shares trades on the TSX or such other stock exchange on which the greatest number of Common Shares are traded). As at March 4, 2020, there are 740,307 TAC Preferred Shares issued and outstanding. Assuming all TAC Preferred Share exchange rights are exercised, Tamarack would issue 711,834 Common Shares.

DIVIDENDS

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

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

DIRECTORS AND EXECUTIVE OFFICERS

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

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Floyd Price ⁽³⁾ <i>Texas, United States</i>	Director since June 17, 2010; Chairman of the Board	Mr. Price is an independent businessman and is currently a director of Cimarex Energy Co., a U.S.-based oil and gas exploration and production company listed on the New York Stock Exchange, since December 2012. He was previously a director of Gastar Exploration Ltd., a U.S.-based oil and gas exploration and production company listed on the NYSE Amex, from June 2010 to January 2013. Mr. Price has served on the boards of several privately-held oil and gas focused entities, and previously was Executive Vice President of Apache Corporation from February 2003 to October 2009.
Jeffrey Boyce ⁽¹⁾⁽²⁾ <i>Alberta, Canada</i>	Director since October 9, 2013	Mr. Boyce is a senior oil and gas executive with over 38 years of domestic and international experience in building, financing and managing public oil and gas companies. He is currently President of Evsam Holdings Ltd., a privately held investment company, since October 2013. Previously he served as Executive Chairman and Director of PetroAmerica Oil Corp. a TSX-V company, from September 2009 until its acquisition by Gran Tierra Energy Inc. in January 2016. Prior thereto, Mr. Boyce was a co-founder, Senior Executive and Director of Sure Energy Inc., Clear Energy Inc. and Vermilion Resources.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Noralee Bradley, QC ⁽³⁾⁽⁴⁾ Saskatchewan, Canada	Director since December 17, 2015	Ms. Bradley is the Chief Legal Officer of Nutrien Ltd. since March 2020. Previously, she was a partner at the national law firm of Blake Cassels & Graydon LLP from September 2017 until March 2020, and prior thereto had been with Osler, Hoskin & Harcourt LLP, since January 2006, focused on mergers and acquisitions, financings and board governance. Ms. Bradley was a member of the executive committee of the Institute of Corporate Directors, Calgary Chapter from 2010-2016 (serving as Chair in 2015-2016), has served on the Executive and Compensation Committees of Osler (2012-2016) and was previously a director of Angle Energy Inc., a TSX listed company, from June 2004 until its acquisition in December 2013. Ms. Bradley served as Corporate Secretary of the Company until December 17, 2015.
Ian Currie ⁽²⁾⁽⁴⁾ Alberta, Canada	Director since March 22, 2017	Mr. Currie is a professional engineer with over 31 years of oil and gas experience. He is currently the President and CEO of Spur Petroleum Ltd., a privately-held oil and gas exploration and production company. Previously he served as President and CEO of Spur Resources, Ltd. from 2006 until its acquisition by Tamarack in January, 2017. Prior thereto, he was Vice President, Operations at Profico Energy Management from its inception in 2000 until its acquisition in 2006, and held senior operational roles with Renaissance Energy Ltd. since 2002.
John Leach ⁽¹⁾⁽³⁾ Alberta, Canada	Director since January 18, 2017	Mr. Leach is a Chartered Professional Accountant (CPA) with over 26 years of oil and gas experience. He is currently the Executive Vice President & Chief Financial Officer of Crew Energy Inc., a position he has held since Crew's spin-out from Baytex Energy Ltd. in 2003. Previously, Mr. Leach was a founding member of Baytex Energy Ltd. since 1993, serving in the finance department in roles of increasing responsibility culminating as its Vice President, Finance from 1998 to 2003. Mr. Leach has been a CPA since 1991 and is a graduate of the University of Saskatchewan.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
David R. MacKenzie ⁽¹⁾⁽²⁾ <i>Alberta, Canada</i>	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.
Brian Schmidt <i>Alberta, Canada</i>	President and Chief Executive Officer Director since June 17, 2010	President and Chief Executive Officer of the Company. He is currently a member of the Board of Governors of the Canadian Association of Petroleum Producers and is the Alberta Executive Policy Group Chairman. He is also an advisor to the Indian Oil & Gas Co-Management Board. Prior thereto, he was President, Chief Executive Officer and a director of privately-held Tamarack Valley Energy Ltd., a predecessor entity to the Company, from August 2009 to June 2010.
Robert Spitzer ⁽³⁾⁽⁴⁾ <i>Alberta, Canada</i>	Director Since June 22, 2017	Mr. Spitzer is an experienced professional in the upstream oil and gas field with over 35 years of industry tenure. Mr. Spitzer is currently an independent businessman. He was previously the Executive Vice President of Apache Kitimat Upstream from 2013-2015 and the Vice President New Ventures of Apache Canada Ltd., a wholly-owned subsidiary of Apache Corporation, from 2005-2012. Prior thereto, Mr. Spitzer held a variety of exploration and development-based positions with Apache Canada Ltd. and Shell Canada Ltd. He has a Master of Science in Remote Sensing (Geologic Application) degree and a Bachelor of Science (Honours) in Geology and Geography, both from McMaster University.
June-Marie Innes <i>Alberta, Canada</i>	Interim CFO	Ms. Innes has been with Tamarack since 2012 and is a CPA with 19 years of oil and gas experience. Prior to Tamarack, Ms. Innes held finance, accounting and administration roles with Anderson Energy Inc., Highpine Oil & Gas Ltd., and Vaquero Energy Ltd.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Dave Christensen <i>Alberta, Canada</i>	Vice President, Engineering	Mr. Christensen has been Vice President, Engineering of the Company since April 2014. Prior thereto, he spent five years at Bonavista Energy Corp with the last four as Development Engineering Manager - West Region, an area in which all of Tamarack's Cardium assets are situated. While at Bonavista, Mr. Christensen managed the drilling of over 300 horizontal wells, and evaluated and closed on more than \$1 billion of acquisitions. Previously, he held various management positions at Norcen Energy, Storm Energy, and Piper Energy.
Ken Cruikshank <i>Alberta, Canada</i>	Vice President, Land	Mr. Cruikshank has been the Vice President, Land of the Company since June 2010 and was appointed an officer of the Company on October 4, 2013. Prior thereto, he was Vice President Land of Vaquero Resources Ltd., which was acquired by RMP Energy Ltd., as well as at a predecessor firm, Vaquero Energy Ltd., which successfully merged with Highpine Oil & Gas Ltd. Previously, Mr. Cruikshank spent seven years as Vice President Land of Beau Canada Exploration Ltd.
Martin Malek <i>Alberta, Canada</i>	Vice President, Business Development and Corporate Planning	Mr. Malek is a professional engineer and has been with Tamarack since April of 2014, previously as Manager, Development Engineering. He has 13 years of oil and gas experience from positions held in Production, Operations and Field Development. He spent nine years at Apache Corporation, two of which he spent working in the Permian Basin of Texas drilling horizontal wells in the Wolfcamp and Spraberry formations.
Scott Reimond <i>Alberta, Canada</i>	Vice President, Exploration	Mr. Reimond was appointed Vice President, Exploration of the Company in October 2012. He had previously been the Exploration Manager of the Company since June 2010 and the Exploration Manager of privately-held Tamarack Valley Energy Ltd. from September 2009 to June 2010. Prior to Tamarack, he was a Senior Geologist with Spearpoint Energy up until its sale to NAL Oil & Gas Trust in 2009, and previously was a Senior Geologist with Rock Energy.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Kevin Screen <i>Alberta, Canada</i>	Vice President, Production and Operations	Mr. Screen is a professional engineer and has been the Vice President, Production and Operations of the Company since September 2011. Prior thereto, he held the positions of Business Unit Manager, Asset Team Leader, and Production Engineer at Apache Canada Ltd. from September 2002 to September 2011.
Sony Gill <i>Alberta, Canada</i>	Corporate Secretary	Mr. Gill is a partner in the Capital Markets and Mergers & Acquisitions Groups at the Stikeman Elliott LLP law firm, with a practice focussing on public and private company creation, growth, restructuring and value maximization. Prior to joining Stikeman Elliott, Mr. Gill was a partner at another major Canadian 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' corporate governance and compensation committee.*
- (4) *Member of the Board of Directors' health, safety and environment committee.*

As of February 27, 2020, 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 5,255,845 Common Shares, representing approximately 2.4% of the Common Shares issued and outstanding on a non-diluted basis.

Cease Trade Orders

To the knowledge of management, no director or executive officer of the Company is, as at the date of this AIF, or has been, within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company) that: (i) was subject to an order (as defined below) that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

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

Bankruptcies

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

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

AUDIT COMMITTEE INFORMATION

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

Audit Committee Mandate

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

Composition of Audit Committee

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

Relevant Education and Experience

David R. MacKenzie

Mr. MacKenzie is a professional engineer and independent businessman with over 36 years of oil and natural gas experience. Mr. MacKenzie is the long-time President of the Lincoln Group of Companies which has been making private equity investments in the oil and natural gas, technology and real estate industries since 1990. While leading the Lincoln Group of Companies, Mr. MacKenzie has occasionally served as a director and/or executive officer of certain companies in which the Lincoln Group has invested in including having served as President of Avant Garde Energy Corp. from September 2009 until its acquisition by Tamarack in June 2010. Mr. MacKenzie has also served on the boards of directors of numerous publicly-held companies such as TUSK Energy Company from January 2007 to April 2009, Zenas Energy Corp. from August 2005 to December 2006, and Blizzard Energy Inc. from December 2003 to July 2005, including having served on the audit committees of these three companies. In these roles, Mr. MacKenzie has acquired experience and exposure to accounting and financial reporting issues, as well as capital markets procedures, policies and rules.

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

John Leach

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

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

Jeffrey Boyce

Mr. Boyce is a senior oil and gas executive with over 38 years of domestic and international experience in building, financing and managing public oil and gas companies. He is currently President of Evsam Holdings Ltd., a privately held investment company. Previously, he served as Executive Chairman and Director of PetroAmerica Oil Corp. prior to its acquisition in 2016, and was a co-founder, Senior Executive and Director of Sure Energy Inc., Clear Energy Inc. and Vermilion Resources Ltd. His background in oil and gas affords expertise across numerous areas, including financial markets, business development and exploration and land strategies, as well as corporate planning and negotiations. Throughout his career, he has served as a director and chairman or CEO of multiple oil and gas companies of varying sizes and has transacted on numerous acquisitions, dispositions or financings. Mr. Boyce obtained an Education Diploma in Business from Durham College in 1980 and received his Professional Landman Accreditation (P. Land) in 1992.

Audit Committee Oversight

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

Reliance on Certain Exemptions

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

Pre-Approval Policies and Procedures

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

External Auditor Service Fees (by Category)

Audit Fees

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

Year Ended December 31	2019	2018
Audit fees ⁽¹⁾	311,000	287,000
Audit-related fees ⁽²⁾	-	-
Tax fees ⁽³⁾	-	-
All other fees ⁽⁴⁾	24,940	-
Total fees	\$335,940	\$287,000

Notes:

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

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations. Controls relating to land tenure, royalties and taxes, exploration, development, production, refining, transportation and marketing, among other things, are imposed by legislation and regulation enacted by both the federal and provincial levels of government all of which should be carefully considered by investors in the oil and natural 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. While all current legislation is a matter of public record, Tamarack is unable to predict what additional legislation or amendments may be enacted by governments in the future. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

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; however, regional market and transportation issues also influence prices. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms.

Natural Gas Liquids

The pricing of condensates and other NGL such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the National Energy Board Act (the "NEB Act") with the Canadian Energy Regulator Act (Canada) (the "CERA"), and replacing the National Energy Board (the "NEB") with the CER. The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGL from Canada are subject to CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g., NGL), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGL. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export license, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("Cabinet") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGL) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m³ per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from the Western Canada to the U.S. and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In

addition, production of crude oil, natural gas and NGL in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints, Pipeline Capacity and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process, with the CER, which aims to create efficiencies in the project approval process, while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian petroleum and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and

orders issued prior to the Federal Court of Appeal decision quashing the original certificate of public convenience and necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding the Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the Government of British Columbia submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the Environmental Management Act to impose a permitting requirement on carriers of heavy crude oil within British Columbia. The British Columbia Court of Appeal answered the reference questions unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal.

While it was expected that construction on the Keystone XL Pipeline, owned by Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court judge determined the underlying environmental review was inadequate. The United States Department of State issued its final supplemental environmental impact statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

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

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents; however, nothing has been publicly announced indicating the fate of the program, or whether any of the contracts have been sold to industry proponents.

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better

pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and U.S. natural gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd. ("**Pieridae**"), would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserve space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1, 2019 the Government of Alberta, on a monthly basis, subjects oil producers producing more than 20,000 bbl/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbl/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The Curtailment Rules are set to be repealed by December 31, 2020.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA / CUSMA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, referred to as the United States Mexico Canada Agreement or the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the CUSMA before it comes into force. Mexico's senate ratified the CUSMA in June 2019. In late December 2019, the United States' House of Representatives approved the CUSMA and the CUSMA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the CUSMA. According to Bill C-4, the CUSMA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, the implementation of the final version ratified version of the CUSMA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Company's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the CUSMA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The CUSMA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the CUSMA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, and Singapore. On January 14, 2019, the CPTPP came into force for Vietnam.

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

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

Extractive Sector Transparency Measures Act

In 2015, the federal government's Extractive Sector Transparency Measures Act ("**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD\$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments (i.e. the Crown). 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. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations

that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

An additional category of mineral rights ownership includes ownership by the Canadian Federal Government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the Indian Oil and Gas Act (the "**IOGA**") and the Indian Oil and Gas Regulations, 1995 (the "**1995 Regulations**"). In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards.

The gross overriding royalty interests ("**GORR Interests**") are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, as discussed above, the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to non-productive geological formations at the conclusion of the primary term of a lease or licence.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, 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 have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL.

The federal government may from time to time provide incentives to the petroleum and natural gas industry. In November 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide crude oil and natural gas businesses with eligible Canadian development expenses ("**CDE**") and Canadian crude oil and natural gas property expenses ("**COGPE**") with a first-year deduction of one and a half times the deduction that is otherwise available for CDE and COGPE. The definitions of "**accelerated CDE**" and "**accelerated COGPE**", as amended in November 2018, allow oil and gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successor expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

The federal government also announced in late 2018 that it would make \$1.6 billion available to the petroleum and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed \$629 million among 37 companies, of \$1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totaling \$207.5 million out of its \$500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced \$49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed \$37 million of a \$50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

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

Alberta

On January 29, 2016, the Government of Alberta announced further changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5% royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. Any changes to the royalty regime in Alberta may have a material effect on the Company. See "*Risk Factors*".

In addition to any negotiated royalty amount payable to the freehold mineral owner, producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of

production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4 percent of revenues reported from fee simple mineral title properties.

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

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the oil and gas rights, with the remainder being freehold lands. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights acreage tax is charged to mineral rights holders paid on an annual basis at the rate of \$1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGL is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay Freehold Mineral Taxes or production taxes. Freehold Mineral Taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the Freehold Mineral Taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Production and Operation Regulations

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

Regulatory Authorities and Environmental Regulation

The Canadian oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties.

In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions including carbon dioxide equivalents ("**CO₂e**"), may impose further requirements on operators and other companies in the petroleum and natural gas industry.

Federal

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

On August 28, 2019, with the passing of Bill C-69, the CERA and the Impact Assessment Act ("**IAA**") came into force and the NEB Act and the (CEAA) were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The IA Agency must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75 kilometres of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals.

The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the Oil Tanker Moratorium Act which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53'00" north latitude and west of 126°38'36" west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The discharge of crude 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 in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

The Alberta Energy Regulator ("**AER**") is the single regulator responsible for all energy development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related acts including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta 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. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. The Oil and Gas Conservation Act ("**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with The Oil and Gas Conservation Regulations 2012 and The Petroleum Registry and Electronic Documents Regulations. The aim of SKOGCA and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Liability Management Rating Programs

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses.

This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in Redwater Energy Corporation (Re) ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings.

This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In response to Redwater's trajectory through the court, the AER introduced amendments to its liability management framework. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years.

All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

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

2017, this number fell from 17,470 to 12,375 non-compliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released its subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR of below 1.0) to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LMR calculation in evaluating deposit requirements, and that further changes may be forthcoming.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company's business and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at \$10/tonne, increasing annually until it reaches \$50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of \$20/tonne of GHG emissions. Under current federal plans, this price will escalate by \$10 per year until it reaches a price of

\$50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is \$30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems in place that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario challenged the constitutionality of the federal government's pricing regime. On February 24, 2020, the Alberta Court of Appeal held in a non-binding ruling, that the federal carbon tax is unconstitutional. The Federal Justice Minister has indicated that this decision will be appealed to the Supreme Court of Canada. Conversely, appellate courts in Saskatchewan and Ontario and the Attorney General of Saskatchewan have appealed such rulings to the Supreme Court of Canada. The Court is set to hear the appeals in March of 2020. Ontario and Saskatchewan will cross-intervene in the appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba, British Columbia, and Alberta, who will intervene in both proceedings.

On April 26, 2018, the Federal Government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The Federal Government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). Under this strategy, the Climate Leadership Act (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions. In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of \$20/tonne. In accordance with the GGPPA, this will increase to \$30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies to industry-wide to emitters that emit more than 100,000 tonnes of CO₂e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available

to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO₂e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the Methane Emission Reduction Regulation (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting ("**Directive 060**"). The release of Directive 060 complements a previously released update to Directive 017: Measurement Requirements for Oil and Gas Operations that took effect in December 2018.

Together, these new directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed \$1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. Both projects will help reduce the CO₂ emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. This legislation is intended to encourage new carbon capture and storage projects in Alberta.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the government released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030. The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations, and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations. These regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the Saskatchewan O&G Emissions Regulations) came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO₂e per

year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO₂e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO₂e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, Bill 147 – An Act to amend The Oil and Gas Conservation Act, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

RISK FACTORS

The Company is subject to both risks that directly affect our business and operations, as well as indirect risks that impact third parties or industry generally. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with Tamarack's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally. If any event arising from the risk factors set forth below occurs, Tamarack's business, prospects, financial condition, results of operation or cash flows and in some cases, its reputation, could be materially adversely affected.

Weakness in the Oil and Natural Gas Industry

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the U.S. and Iran, isolationist trade policies, increased U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. See "*Risk Factors - Political Uncertainty*". These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation, see "*Royalties and Incentives*", "*Regulatory Authorities and Environmental Regulation*" and "*Climate Change Regulation*" in "*Industry Conditions*". In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the crude oil and natural gas industry in Western Canada has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada (see "*Industry Conditions - Transportation Constraints, Pipeline Capacity and Market Access*").

Lower commodity prices may also affect the volume and value of the Company's reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Company's cash flow which could result in a reduced capital expenditure budget. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year-over-year basis. See "*Risk Factors - Reserve Estimates*". A prolonged period of adverse market conditions may impede the Company's ability to refinance its Credit Facility or arrange alternative financing when the Credit Facility becomes due or if the lending limits under the Credit Facility are reduced upon periodic review. See "*Risk Factors - Credit Facility Arrangements*". Given the current market conditions and the lack

of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Tamarack's cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations. See "*Risk Factors - Additional Funding Requirements*".

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.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect production, which may reduce the Company's revenue.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

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

Commodity Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired, discovered or produced by Tamarack is, and will continue to be, affected by numerous factors beyond its control. The Company's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets or contract for the delivery of crude oil by rail (see "*Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access*" and "*Risk Factors - Weakness in the Oil and Natural Gas Industry*"). The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines processing and storage facilities; and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of Tamarack's anticipated 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 natural gas and a reduction in the volumes of Tamarack's reserves. Tamarack might also elect not to produce from certain wells at lower prices.

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See "*Risk Factors - Weakness in the Oil and Natural Gas Industry*".

All of these factors could result in a material decrease in Tamarack's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business and financial condition.

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 trading price of securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of commodities has increased due to, in part, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds

only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in crude oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities.

Similarly, the market price of the Common Shares may be due to Tamarack's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Tamarack or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*". In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Reliance on Operators, Management and Key Personnel

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. 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. The contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company. In addition, Tamarack may not be the operator of certain oil and natural gas properties in which it acquires an interest. To the extent Tamarack is not the operator of its oil and natural gas properties, Tamarack will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

Credit Facility Arrangements

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

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

Borrowing

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

Substantial Capital Requirements

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

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

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

Additional Funding Requirements

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

As a result of global economic and political volatility, Tamarack may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company

to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Tamarack's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely. In addition, the future development of Tamarack's properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing could be highly dilutive to existing shareholders. Failure to obtain any financing necessary for Tamarack's capital expenditure plans may result in a delay in development or production on the Company's properties.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of crude oil and gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and indigenous rights, have affected certain investors' sentiments towards investing in the crude oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the crude oil and natural gas industry, and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment change.

Evolving Corporate Governance and Reporting Framework

The Company's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company's securities. Tamarack is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Reputational Risk

The Company's business, financial condition, operations or prospects may be negatively impacted as a result of any negative public opinion toward Company or as a result of any negative sentiment toward or in respect of Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain crude oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by Tamarack's operations could damage the reputation of the Company in active operational areas. The Company's reputation could be affected by actions and activities of other corporations operating in the crude oil and natural gas industry, over which the Company has no control. If the Company, either directly or indirectly, develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Company's reputation. In addition, environmental damage, loss of life, injury or damage to property caused indirectly by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and cash flows to be derived therefrom, including many factors beyond Tamarack's control. The information concerning reserves and associated cash flow set forth in this AIF represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as: historical production from the properties; production rates; ultimate reserve recovery; timing and amount of capital expenditures; marketability of oil and natural gas; royalty rates; the assumed effects of regulation by governmental agencies; and future operating costs, all of which may vary from actual results.

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Tamarack's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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

In accordance with applicable securities laws, GLJ has used forecast price and cost estimates based on averages from three different independent evaluators' price forecasts in calculating reserves quantities. See "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*". Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the GLJ Report and such variations could be material. The GLJ Report is based in part on the assumed success of activities Tamarack intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and

contained in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report. The GLJ Report is effective as of December 31, 2019, with a preparation date of January 27, 2020, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Title to Assets

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Hedging

From time to time, Tamarack may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; Similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, Tamarack may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk 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. In addition, if the Company enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the

hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to U.S. dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

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 adjusted funds flow. 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 or 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. To the extent that any such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's business and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

Operating costs incurred by Tamarack are generally paid in Canadian dollars. World crude oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar negatively impact Tamarack's production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Tamarack's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results.

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.

The Company competes with other exploration and production companies, any of whom may have more financial resources, staff or political influence than the Company. Tamarack's ability to increase its production in the future will depend not only on its ability to develop the Company's properties, but also on its ability to select other suitable assets for further exploration and development.

Political Uncertainty

In the last several years, the U.S. and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the U.S. from the CPTPP and Congress has passed sweeping tax reform, which among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the CUSMA which will replace NAFTA once ratified by the three signatory countries. See "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the administration in the U.S. will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian oil and natural gas companies, including Tamarack.

The CUSMA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the CUSMA. The CUSMA is expected to fully replace NAFTA two months after Bill C-4 comes into force (see "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*"). The U.S. administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian oil and natural gas companies, including the Company.

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

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy.

Alberta elected a new government in 2019, that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the Government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for exploration and production companies, such as Tamarack.

The federal government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty,

the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry. See *"Industry Conditions – Climate Change Regulation"*, *"Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access"*, *"Industry Conditions – Curtailment"* and *"Industry Conditions – The North American Free Trade Agreement and Other Trade Agreements"*.

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 outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of crude 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.

Non-Governmental Organizations and Eco-Terrorism Risks

The crude oil and natural gas industry may, at times, be subject to public opposition. Such public opposition could expose Tamarack to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and direct legal challenges, including the possibility of climate-related litigation (see *"Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access"*). There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Company's business, financial condition, results of operations and prospects.

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack which may have a material adverse effect on its business, financial condition, results of operations and prospects. Tamarack does not have insurance to protect against the risk of terrorism.

Waterflood

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

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from crude oil and natural gas wells is subject to ongoing regulatory review by federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the costs of compliance for Tamarack which may impact the economics of certain projects and in turn impact activity levels and new capital spending on the Company's properties.

Cost of New Technologies

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

Environmental Regulation

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities and sets out the requirements with respect to oilfield waste handling and storage and habitat protection.

Compliance with environmental legislation can require significant expenditures and a breach of such legislation may result in the imposition of fines or other penalties, some of which may be material, as well as the responsibility to remedy environmental problems caused by Tamarack's operations. See *"Industry Conditions — Regulatory Authorities and 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 – Regulatory Authorities and Environmental Regulation"*.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by such third parties, which could impact the availability of capital to be spent by them which could in turn materially adversely affect the Company's business and financial condition. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation"* and *"Industry Conditions – Liability Management Rating Programs"*.

Regulatory

Oil and natural gas operations (exploration, development, production, pricing, marketing, transportation and infrastructure) are subject to extensive controls and regulations imposed by various levels of government and may be amended from time to time. Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of crude oil and natural gas and infrastructure projects. Amendments to these controls and regulations, including changes to royalty regimes or the calculation of production and mineral taxes, may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, or make certain projects on the Company's assets uneconomic, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime as the implementation of the orders can be delayed resulting in uncertainty and interruption to business of the crude oil and natural gas industry. See "*Industry Conditions - Climate Change Regulations*" and "*Industry Conditions - Curtailment*". Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact crude oil and natural gas operations and may affect the Company's business and financial condition. See "*Industry Conditions - Climate Change Regulation*". Further, in response to widening pricing differentials, the Government of Alberta implemented production curtailment (see "*Industry Conditions - Curtailment*").

Tamarack's operations require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that Tamarack will be able to obtain all necessary permits, licences, registrations, approvals and authorizations to carry out exploration and development at its projects. In addition, certain federal legislation such as the Competition Act (Canada) and the Investment Canada Act could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. 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. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Programs*".

Royalty Regimes

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

Climate Change

Chronic Climate Change Risks

The Company's exploration and production facilities and other operations and activities emit GHG's and require the Company to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. 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.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal

weather patterns. See "*Risk Factors – Seasonality and Extreme Weather Conditions*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Company to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chains, transport needs, and employee safety, which may in turn have a material adverse effect on the Company. Specifically, in the event of water shortages or sourcing issues, the Company may not be able to, or will incur greater costs to, carry out hydraulic fracturing.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which influenced investors' willingness to invest in the petroleum and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term, potentially reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes. See "*Industry Conditions - Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks*", "*Risk Factors – Reputational Risk*" and "*Risk Factors – Changing Investor Sentiment*".

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

Acute Climate Change Risks

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with the Company's operations, increasing its costs and otherwise negatively impacting its operations. Moreover, extreme weather conditions may lead to disruptions in the Company's ability to transport produced oil and natural gas as well as goods and services in its supply chains. The Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting the Company's operations.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays,

increased operating costs, third party or governmental claims, and could increase the costs of compliance and doing business as well as delay the development of crude oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that is ultimately produced from the reserves associated with Tamarack's assets and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Availability and Cost of Equipment, Material and Qualified Personnel

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment, including 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. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. 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 future growth and integration of additional lands, assets and acquisitions 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 integration growth could have a material adverse impact on its business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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

Income Taxes

Tamarack files all required income tax returns and believes that it is in full compliance with the provisions of the *Tax Act* and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable. Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that affects the Company. Furthermore, tax authorities having jurisdiction over Tamarack may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Tamarack's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; availability and productivity of skilled labour; and regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Conflicts of Interest

Certain directors and officers of Tamarack are also, or may in the future be, directors or officers of other oil and natural gas companies, that may compete or be counterparties to agreements with the Company and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA and the Company's policies 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, or material transaction, or proposed material transaction, with the Company 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. The Company also has additional policies in place which require management to seek approvals of independent directors in certain situations where there may be a perceived or potential conflict of interest arising due to interlocking directorships, despite the transaction being within management's authorization levels and not otherwise requiring Board approval. See "*Directors and Officers – Conflicts of Interest*".

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may make the ground unstable, limit access and, as a result, cause 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to Tamarack's properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

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. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. 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.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. Claims and protests of indigenous peoples may disrupt or delay third-party operations or new development on the Company's properties. 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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Company's business and financial condition.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Climate Change Regulation*". The taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Insurance

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

Litigation

In the normal course of Tamarack's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Tamarack and as a result, could have a material adverse effect on Tamarack's assets, liabilities, business, financial condition and results of operations. Even if Tamarack prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Gathering and Processing Facilities, Pipeline Systems and Rail

The products Tamarack produces must be delivered through gathering, processing and pipeline systems, some of which are not owned by the Company, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from Tamarack's assets is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the petroleum and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed the challenges to the Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway (see "*Industry Conditions – Pricing and Marketing in Canada*" and "*Industry Conditions - Transportation Constraints, Pipeline Capacity and Market Access*" and "*Industry Conditions - Curtailment*"). In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export oil and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition.

As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEA 2012 were repealed. In addition, the IA Agency replaced the CEA Agency. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Federal*". The impact of the new federal regulatory scheme on proponents and the timing for receipt of approvals of major projects is unclear.

A portion of Tamarack's production is processed through facilities owned by third parties over which the Company has no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of third party facility operations could have a materially adverse effect on Tamarack's production and ability to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Breach of Confidentiality

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

Information Technology Systems and Cyber-Security

Tamarack has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure, and its ability to expand and continually update this infrastructure, to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, manage financial resources, analyze seismic information, administer contracts and communicate with employees and third-party partners.

The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of Tamarack's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber-phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such phishing attacks through education and training, phishing activities remain a serious problem that may damage our information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems, including written incident response plan for responding to a cyber security incident. However, these controls may not adequately prevent cyber-security breaches.

Increasingly, social media is used as a vehicle to carry out cyber-phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Company's systems and obtain confidential information. The Company periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as reputation. Tamarack applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Access to Company Offices and Properties

The Company's ability to carry on its business is dependent upon the ability of its employees to physically access its offices and properties. If access to the Company's office or properties is interrupted, then the Company's ability to administer and manage its business may be materially and adversely affected.

Limited Ability of Residents in the U.S. to Enforce Civil Remedies

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the U.S. As a result, it may be difficult for investors in the U.S. to effect service of process within the U.S. upon such directors, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments of the U.S. courts based upon civil liability under the U.S. federal securities laws or the securities laws of any state within the U.S. There is doubt as to the enforceability in Canada against the Company or against any of our directors, officers or representatives of experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or securities laws of any state within the U.S.

Forward-Looking Information May Prove Inaccurate

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of \$56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of \$1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged the Company has breached its fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners. The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in the consolidated financial statements.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below, to the knowledge of the directors and officers of the Company, none of the directors or executive officers of the Company, nor any person or Company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any of their respective associates or affiliates, has

or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the Company's current year or in any proposed transaction which has materially affected or is reasonably expected to materially affect the Company.

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

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the GLJ Report prepared by GLJ, an independent reserves evaluator. As of January 31, 2020, 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.

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

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

ADDITIONAL INFORMATION

Additional information regarding Tamarack may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the Company's management information circular dated April 10, 2019 relating to the annual meeting of shareholders held on May 13, 2019. 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, 2019.

DEFINITIONS

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

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

"AER" means Alberta Energy Regulator, an Alberta corporation responsible for regulating the development of energy resources in the province;

"**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;

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

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

"**CER**" means the Canadian Energy Regulator;

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

"**CETA**" means the Comprehensive Economic and Trade Agreement, which Canada and the European Union recently agreed to;

"**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;

"**CPTPP**" means Comprehensive and Progressive Agreement for Trans-Pacific Partnership;

"**Credit Facility**" means the credit facilities of the Company with a syndicate of Canadian chartered banks, consisting of an extendible revolving syndicated term credit facility in the amount of \$320 million and an extendible revolving working capital credit facility in the amount of \$30 million; next annual review before May 31, 2020;

"**CUSMA**" means the Canada United States Mexico Agreement, sometimes referred to as the United States Mexico Canada Agreement or "USMCA";

"**ESTMA**" means the federal government's Extractive Sector Transparency Measures Act;

"**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;

"**GHG**" means greenhouse gas;

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

"**GLJ Report**" means the independent engineering report dated January 31, 2020 and evaluating the crude oil, natural gas and NGL reserves of the Company effective as of December 31, 2019;

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

"**MRF**" means modern royalty framework;

"**NCIB**" means Normal Course Issuer Bid;

"**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*;

"OPEC" means Organization of the Petroleum Exporting Countries;

"OTMA" means the Oil Tanker Moratorium Act which came into force on June 21, 2019;

"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.";

"RSU" means Restricted Share Units;

"PRSU Plan" means the Performance and Restricted Share Unit Plan that allows the Board of Directors to grant performance awards to officers, employees and consultants of the Company or its subsidiaries;

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

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

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

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

"Sure Energy" means Sure Energy Ltd.;

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

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

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

"TSX" means the Toronto Stock Exchange;

"TSX-V" means the TSX Venture Exchange;

"TVE" is the trading symbol of the Company on the TSX;

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

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

"WCSB" means Western Canadian Sedimentary Basin.

CONVENTIONS

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

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

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

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

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

SELECTED CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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", "budget", "continue", "evaluate", "monitor", "can", "able", "potential", "consider", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "focus", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company's presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Tamarack bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions. Management believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements should not be unduly relied upon.

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

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

- drilling plans, expectations and timing of drilling;
- the Company's ability to attract and retain qualified personnel;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- Common Share buy-backs for cancellation under the NCIB and RSU settlements;
- treatment under governmental regulatory regimes and tax laws;
- expected effect of regulatory regimes and controls;
- tax horizon and future income taxes;
- use of Credit Facility funds;
- the Company's capital program and guidance for 2020;
- expected source of funds in connection with the Company's capital program;
- expectations regarding commodity prices in 2020;
- deployment of the Company's 2020 capital program;
- expectations regarding dividends;
- the expected allocation of the Company's 2020 capital expenditure budget;
- the source of funds for the Company's 2020 expenditure budget;
- capital expenditure programs and the timing and method of financing thereof; and
- abandonment and reclamation costs.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. See "*Statement of Reserves Data and Other Oil and Gas Information*".

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

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

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

- volatility in market prices for oil and natural gas;
- lack of transportation and inability to produce oil and natural gas reserves and resources;
- adverse regulatory rulings, orders and decisions;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling and processing problems and other problems in producing reserves and resources;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- stock market volatility and market valuations;
- the impact of climate change and climate change regulations;
- possible renegotiation and replacement of international trade agreements including NAFTA;
- the risks of the oil and natural 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 natural gas industry;
- changes in income tax laws or changes in tax laws or trade laws and incentive programs relating to the oil and natural gas industry;
- the effect of litigation proceedings outlined above on the Company's business; and
- the other factors discussed under "*Risk Factors*".

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

OIL AND GAS MEASURES

This AIF discloses drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved locations and probable locations derived from an internal evaluation using standard practices as prescribed in the Canadian Oil and Gas Evaluations Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable. The drilling locations identified herein can be further broken down as follows:

Area	Drilling Locations	Booked - Proved	Booked - Probable	Unbooked
	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)
Wilson Creek/Alder Flats/Pembina Cardium	175 (142.2)	46 (40.2)	30 (25.9)	99 (76.1)
Wilson Creek/Alder Flats/Pembina Non-Cardium	11 (7.3)	4 (2.3)	7 (5)	0 (0.0)
Veteran/Consort Viking Primary	270 (264.0)	170 (165.6)	92 (89.8)	8 (8.6)
Veteran/Consort Viking Waterflood	900 (900.0)			900 (900.0)
North Hoosier/Milton/Coleville Viking	116 (108.2)	39 (36.2)	42 (37.6)	35 (34.4)
Redwater Viking	114 (107.5)	52 (49.5)	62 (58.0)	0 (0.0)
Redwater Ellerslie	32 (29.3)	11 (10.0)	6 (5.5)	15 (13.8)
Lethbridge Barons Light Oil	12 (12.0)	7 (7.0)	5 (5.0)	0 (0.0)
Lethbridge Banff Light Oil	19 (15.0)	0 (0.0)	5 (5.0)	14 (10.0)

Notes:

- (1) As the Cardium horizontal locations have varying lateral lengths, the Company maintains its inventory on a one-mile equivalent basis. The one-mile equivalent Wilson Creek/Alder Flats/Pembina Cardium locations for each of the categories above are as follows: 289 (239.8 net) drilling locations; 75 (65.6 net) booked proved locations; 45(39.0net) booked probable locations; and 170 (135.2 net) unbooked locations.

Unbooked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and natural gas reserves, resources or production.

NON-IFRS MEASURES

This document contains the terms "adjusted funds flow", "operating netback", "operating field netback", "funds from operations", "cash flow", "net debt to annualized adjusted funds flow ratio", "net debt", "netbacks", "debt adjusted production per share growth" and "capital cost payout", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

The Company uses adjusted funds flow ratio as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (bank debt plus working capital deficiency, excluding the fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers operating netback a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and net production and transportation costs from petroleum and natural gas sales, including realized gains and losses on commodity, interest rate and foreign exchange derivative contracts. The Company also considers capital cost payout a key measure as it demonstrates the financial status of the Company's projects. Net debt to annualized adjusted funds flow ratio is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter.

(a) Adjusted funds flow - Tamarack's method of calculating adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted funds flow is calculated by taking net income or loss before taxes and adding back items, including transaction costs, and certain non-cash items including stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; impairment; unrealized gain or loss on financial instruments; and gain or loss on dispositions. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares used in calculating income (loss) per share. The calculation of the Company's adjusted funds flow can be seen on page 14 of the Company's 2019 Management's Discussion and Analysis in the section titled "*Adjusted funds flow and Net Income (Loss)*".

(b) Operating Netback and Operating Field Netback - Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. These benchmarks do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties and net production and transportation costs. Operating field netback equals total petroleum and natural gas sales, less royalties and net production and transportation costs. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company's netbacks can be seen on page 9 of the Company's 2019 Management's Discussion and Analysis in the section titled "*Operating Netback*".

(c) Net Debt - Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The Company uses net debt (bank debt plus working capital deficiency, excluding the fair value of commodity and foreign exchange financial instruments) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

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

(e) Net Debt to Annualized Adjusted funds flow – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of a company and its ability to pay off its debt and take on new debt, if necessary, using the most recent quarter's results.

(f) Adjusted Production per Share Growth - Management uses certain measurements as debt adjusted production per share growth, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt-adjusted share count is calculated as total shares outstanding plus incremental shares issued at a current market price to eliminate the change in net debt or in the case where debt decreases the reduction in shares. Management of Tamarack believes that debt adjusted production per share is useful in determining the production growth on a per share basis as if changes to debt was extinguished by the issuance or redemption of shares. The presentation of production growth on a per share basis is skewed for oil and gas companies that have more debt on their balance sheet and in their capital structure. Such companies will show better results because more of their growth is financed through debt than equity (as opposed to generating growth through realizing a rate of return on capital employed). The debt adjusted production per share measure provides a means of putting oil and gas companies on an equal, enterprise-based footing with respect to debt when calculating per share numbers. This measure is relevant to investors to appreciate the impact the debt on a company's balance sheet has on per share growth disclosure and the strength of one company's balance sheet relative to an over-leveraged peer, particularly in volatile commodity price environments where a company's indebtedness may increase as a result of lower cash flows and higher debt financing costs.

APPENDIX "A"

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

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

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

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Valuation	Location of Reserves (Country)	NPV10 Audited (\$000)	NPV10 Evaluated (\$000)	NPV10 Reviewed (\$000)	NPV10 Total (\$000)
GLJ Petroleum Consultants Ltd.	Dec 31/19	Canada	0	1,476,400	0	1,476,400

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 31, 2020.

"Originally Signed by"

Leonard Herchen, P. Eng.
Vice President

APPENDIX "B"

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

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

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

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

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and natural 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 natural gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

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

(signed) "Brian L. Schmidt"

Brian L. Schmidt, President & CEO

(signed) "Dave Christensen"

Dave Christensen, Vice President, Engineering

(signed) "Ian Currie"

Ian Currie, Director

(signed) "David MacKenzie"

David MacKenzie, Director

(signed) "Jeff Boyce"

Jeff Boyce, Director

March 4, 2020

APPENDIX "C"

AUDIT COMMITTEE MANDATE

Policy Statement

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

Composition

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

Meetings and Operations

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

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

Authority and Reporting

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

Primary Duties and Responsibilities

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

- (d) review any problems experienced or concerns expressed by the auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;
- (e) review with management the process of identifying, monitoring and reporting the Corporation's risk management policies and procedures and the principal risks affecting financial reporting;
- (f) review and evaluate any recommendations of the auditors and decide the appropriate course of action;
- (g) consider consistency of the data reported in the financial statements, annual and quarterly reports and related public disclosure documents;
- (h) review audited annual financial statements and related documents in conjunction with the report of the auditors and significant variances between comparative reporting periods as set out in the MD&A;
- (i) review, independently of management, and without management present, the results of the annual external audit, the audit report thereon and the auditor's review of the related MD&A, and discuss with the auditor the quality of accounting principles used, any alternative treatments of financial information that have been discussed with management, the ramifications of their use and the auditor's preferred treatment and any other material communication with management;
- (j) consider and review with management:
 - (i) all unadjusted errors identified by the external auditors,
 - (ii) the internal control memorandum or management letter containing the recommendations of the auditors and management's response, if any, including any evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weakness;
- (k) review with management and the auditors the quarterly unaudited financial statements and MD&A before release to the public;
- (l) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectus, annual reports, annual information forms, MD&A and press releases;
- (m) review and approve the Corporation's hiring policies regarding employees and former employees of the present and former auditors;
- (n) review with management the Corporation's relationship with regulators and the timelines and accuracy of the Corporation's filings with regulatory agencies; and
- (o) review with management all related party transactions and the development of policies and procedures related to those transactions.

Auditors

1. The Committee shall:
 - (a) consider the independence and performance of the auditors and annually recommend to the Board the appointment or discharge of the auditor when circumstances are warranted and recommend to the Board the compensation of the auditors;
 - (b) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the auditors, or the auditors of any of the Corporation's subsidiary entities;
 - (c) when there is to be a change of auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and related documentation required pursuant to National Instrument 51-102 - Continuous Disclosure Obligations, with respect to a change of auditors (or any successor legislation) and the planned steps for an orderly transition period;
 - (d) review all material written communications between the auditor and management; and

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

Financing Matters

1. The Committee shall:
 - (a) review all securities offering documents (including documents incorporated therein by reference) of the Corporation;
 - (b) review findings, if any, from examinations or reviews performed by regulatory agencies with respect to financial matters;
 - (c) review management's consideration of the Corporation's compliance with laws and regulations;
 - (d) review management's assessment of current and expected future compliance with covenants under any financing agreements;
 - (e) if requested by the Board, review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases, as well as any related securities filings;
 - (f) if requested by the Board, review the proposed repurchase of public and private debt, equity and hybrid securities; and
 - (g) in consultation with management understand the Corporation's capital structure and financial risks arising from exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit and review the management of these risks including any proposed hedging of the exposures, including receiving a summary report of the hedging activities and hedge-related instruments.

Other

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

Scope and Reliance

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

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

Pre-Approval Policies and Procedures

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