2021

ANNUAL INFORMATION FORM

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2021
DATED MARCH 3, 2022

tamarack valley ENERGY

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APPENDIX "A" FORM 51-101F2 REPORT OF RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

APPENDIX "C" AUDIT COMMITTEE MANDATE

The information in this AIF is given as of December 31, 2021 unless otherwise indicated.

TAMARACK VALLEY ENERGY LTD.

BACKGROUND

Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is an oil and natural gas exploration and production company committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily on the Charlie Lake, Clearwater and enhanced oil recovery ("**EOR**") plays in Alberta. Operating as a responsible corporate citizen is a key focus to ensure the Company delivers on its environment, social and governance ("**ESG**") commitments and goals. Through multiple accretive acquisitions since inception, Tamarack has successfully assembled an extensive inventory of low-risk oil development drilling locations that are economic over a range of oil and natural gas prices. With this type of portfolio and a talented and committed team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its 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 the 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 long-term value 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.

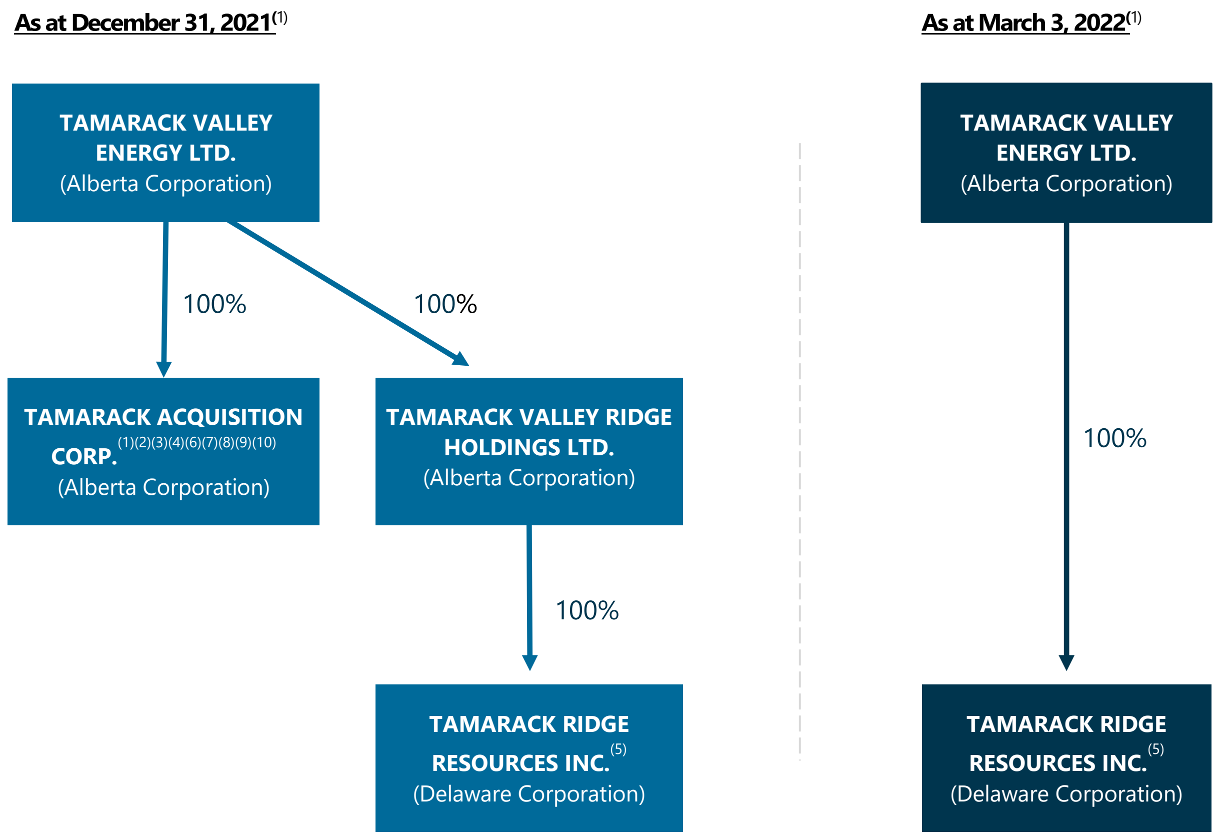
Tamarack is a "reporting issuer" or the equivalent in each of the provinces of Canada. The Common Shares have traded on the TSX under the symbol "TVE" since August 24, 2015. Previously, the Common Shares were trading on the TSX-V.

The Company's head office is located at Suite 3300, 308 – 4th Avenue S.W. Calgary, Alberta, T2P 0H7. The registered office of the Company is located at Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5.

See "*Selected Abbreviations*" and "*Definitions*" for an explanation of capitalized terms and expressions, abbreviations and definitions used in this AIF and not otherwise defined.

Inter-corporate Relationships

The following diagrams presents the name and jurisdiction of incorporation of Tamarack's material subsidiaries as at December 31, 2021 and the date of this AIF.



Notes:

(1) On January 1, 2022, Tamarack Acquisition Corp. ("**TAC**") and Tamarack Valley Ridge Holdings Ltd. were amalgamated with Tamarack Valley Energy Ltd. as part of an internal re-organization of the Company.

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

(3) 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."

(4) 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."

(5) As of the date hereof, no assets are held within Tamarack Ridge Resources Inc.

(6) 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."

(7) On December 21, 2020, Tamarack Acquisition Corp. and Woodcote Oil Corp. completed a horizontal amalgamation under the ABCA to form "Tamarack Acquisition Corp."

(8) As of December 31, 2021, the only material subsidiary of Tamarack was Tamarack Acquisition Corp.

(9) On March 25, 2021, Tamarack Acquisition Corp. and Woodcote Petroleum Inc. completed a horizontal amalgamation under the ABCA to form "Tamarack Acquisition Corp."

(10) On June 1, 2021, Tamarack Acquisition Corp. and Anegada Oil Corp. completed a horizontal amalgamation under the ABCA to form "Tamarack Acquisition Corp."

(11) On February 15, 2022, Tamarack Amalgamation Corp. (a wholly-owned subsidiary of Tamarack that was incorporated solely for the purpose of completing the acquisition of Crestwynd) completed a horizantal amalgamation with Crestwynd Exploration Ltd. under the ABCA to form "Tamarack Amalgamation Corp.". Immediately thereafter, Tamarack Amalgamation Corp. completed a vertical amalgamation with Tamarack under the ABCA to form "Tamarack Valley Energy Ltd."

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Since the Restructuring Transaction, Tamarack has focused on acquiring and developing an attractive land base targeting its light, medium and heavy oil plays as well as oil plays that are candidates for EOR. The Company has continued to successfully execute its business strategy to create long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The following is a summary of the key developments occurring in Tamarack's business over the past three years.

Recent Developments

On February 15, 2022, the strategic acquisition of Crestwynd Exploration Ltd. ("**Crestwynd**") was completed.

On February 10, 2022, Tamarack closed the private placement financing for $200 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 issued in accordance with Tamarack's Sustainability-Linked Bond Framework (the "**SLB Framework**").

On January 31, 2022, Tamarack announced year-end 2021 reserves. Relative to year-end 2020, Tamarack increased proved developed producing reserves ("**PDP**") 39% to 56.3 million boe ("**MMboe**"), Total Proved ("**TP**") reserves 63% to 104.1 MMboe and total proved plus probable ("**TPP**") reserves 64% to 181.9 MMboe in 2021.

On January 13, 2022, Tamarack's Board approved a 2022 capital budget, pro forma the acquisition of Crestwynd, designed to achieve significant free funds. The Company also declared its inaugural monthly dividend of C$0.0083 per share on its issued and outstanding common shares in accordance with its new dividend policy and program. See "Dividends".

Developments in 2021

On March 5, 2021, Mr. John Rooney was appointed to the Company's Board of Directors.

On March 25, 2021, Tamarack completed an asset acquisition in the Clearwater and EOR asset areas and closed the acquisition of Woodcote Petroleum Inc. Additionally, a $68 million equity financing was completed concurrent with the acquisitions.

On June 1, 2021, the Company closed the strategic acquisition of Anegada Oil Corp., a leading Charlie Lake light-oil producer, for total net consideration of $494 million.

On July 27, 2021, Tamarack announced several executive changes, including the retirement of Mr. Floyd Price, Chair of the Board, and Mr. Dave Christensen, VP, Engineering. Concurrently, Mr. John Rooney was elected Chair of the Board, Mr. Kevin Screen was promoted to Chief Operating Officer and Mr. Martin Malek was appointed as successor to Mr. Christensen as VP, Engineering. Further, Ms. Christine Ezinga was appointed VP, Corporate Planning and Business Development and Mr. Scott Shimek was appointed VP, Production and Operations.

On September 13, 2021, a five-year plan was announced highlighting significant free funds flow generation, and the Company's flexibility to direct funds to achieve long-term debt targets, return capital to shareholders and execute on M&A opportunities.

On October 27, 2021, the Company announced the implementation of its dividend policy and return of capital framework, including a sustainable base dividend, enhanced regular dividends and tactical share buybacks, funded through free funds flow.

On November 1, 2021, the Toronto Stock Exchange approved the Company's application for a normal course issuer bid ("**NCIB**"), allowing Tamarack to purchase up to 20,354,360 common shares of the Company over a period of twelve months commencing on November 3, 2021.

On December 2, 2021, the Company released its 2021 Sustainability Report, outlining the Company's continued focus on ESG practices and commitments.

On December 15, 2021, Tamarack transitioned its existing credit facility to a sustainability-linked lending ("**SLL**") facility.

Tamarack's 2021 production averaged 34,562 boe/d (69% oil and natural gas liquids ("**NGL**")), generating adjusted funds flow of $340.3 million ($0.96 per share basic and $0.94 per share diluted). Adjusted funds flow was used to fund $191.2 million in exploration and development capital expenditures which contributed to the 2021 drilling of 106 (101.8 net) productive wells, comprised of 40 (40.0 net) Viking oil wells, 43 (40.0 net) Clearwater oil wells, 13 (13.0 net) Charlie Lake oil wells, two (0.8 net) Falher gas wells and eight (8.0 net) water source and injector wells. During the period, Tamarack also had one (1.0 net) drilled and abandoned location in the Charlie Lake area that was subsequently redrilled at an adjacent location. Tamarack generated an operating netback of $30.11/boe after realized commodity hedging gains/losses.

Developments in 2020

On January 9, 2020, Mr. Ron Hozjan resigned as Vice President, Finance and Chief Financial Officer.

On March 5, 2020 Mr. Steve Buytels was appointed as Vice President, Finance and Chief Financial Officer.

On March 18, 2020, Tamarack announced proactive revisions to its 2020 capital budget and associated guidance in response to events impacting the global oil and gas industry. A comprehensive risk management plan was implemented to deal with the impact of the COVID-19 pandemic.

Effective as of April 3, 2020, Ms. Marnie Smith was appointed to the Board of Directors.

On May 12, 2020, Mr. David MacKenzie and Ms. Noralee Bradley retired from the Board of Directors.

On October 22, 2020, the Company released its inaugural 2020 Sustainability Report. The report outlined the Company's continued focus on ESG practices and the increasingly vital role these factors play in Tamarack's strategy. The Company set commitments and goals related to the focus areas of: governance; health and safety; community engagement; indigenous partnerships; people; land and biodiversity preservation; water management; and emissions management.

On December 21, 2020, Tamarack completed two strategic acquisitions in the Clearwater oil play in the Nipisi area along with interests in the Jarvie area of Alberta, for a total net purchase price of $74.0 million, after deducting the proceeds from the sale of a 2% newly created gross overriding royalty ("**GORR**") on a select portion of the acquired properties (the "**Clearwater Acquisitions**"). Pursuant to the Clearwater Acquisitions, Tamarack acquired approximately 2,000 barrels per day of crude oil production and 107,000 net acres of Clearwater rights. Concurrent with completion of the Clearwater Acquisitions, Tamarack completed a $47 million equity financing, and on December 23, 2020, the Company closed the related GORR disposition.

Tamarack's 2020 production averaged 22,027 boe/d (60% oil and NGLs), generating adjusted funds flow of $122.7 million ($0.55 per share basic and diluted). Adjusted funds flow was used to fund $103.5 million in exploration and development capital expenditures which contributed to the 2020 drilling of 73 (69.9 net) wells, comprised of 57 (55.8 net) Viking oil wells, one (0.8 net) Viking gas well, six (5.3 net) Cardium oil wells, one (1.0 net) Clearwater oil well, two (2.0 net) Penny Banff light oil wells and five (5.0 net) water source and injector wells. Tamarack generated an operating netback of $17.86/boe after realized commodity hedging gains/losses.

Developments in 2019

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 April 4, 2019, the Company announced that the TSX had accepted the notice of intention to commence a new 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.

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) and free funds flow of $40.5 million, driven by $179.0 million of capital expenditures, excluding acquisitions and asset retirement obligation spending, which contributed to the drilling of 149 (144.5 net) wells, comprised of 127 (124.1 net) Viking oil wells, 14 (12.5 net) Cardium oil wells, two (2.0 net) Penny Barons oil wells and six (5.9 net) water source and injector wells, as well as bringing wells drilled in Q4/18 onto production in 2019. Based on GLJ's independent evaluation in 2019, Tamarack demonstrated success in converting proved undeveloped ("**PUD**") reserves to PDP reserves, with PDP reserves increasing by 8% to 34.4 mmboe, TP reserves up 4% to 57.9 mmboe and TPP reserves maintained at 101.6 mmboe relative to 2018. The Company also realized growth of 10% on PDP, 6% on TP and 2% on TPP on a basic per share basis. Tamarack generated an operating netback of $27.47/boe after realized commodity hedging gains/losses. The Company's fourth quarter oil and NGL weighting didn't change materially from the first quarter of 2019 despite the production curtailments imposed by the Government of Alberta.

Significant Acquisitions

On February 15, 2022, Tamarack closed the acquisition of Crestwynd, a privately-held pure play Clearwater oil producer, for total consideration of $184.7 million.

On June 1, 2021, Tamarack closed the Anegada Oil Corp. Acquisition for total net consideration of 105.3 million common shares of Tamarack and $247.5 million in cash and assumed net debt, after deducting the proceeds from the closing of the previously announced 2% GORR. A Form 51-102F4 Business Acquisition Report in respect of the acquisition of Anegada Oil Corp. was filed on SEDAR.

On March 25, 2021, Tamarack closed two strategic acquisitions, one in the Provost and one in the Nipisi areas of Alberta for total net consideration of $135.3 million, after deducting the proceeds from the sale of two 4.0% gross overriding royalties ("**GORR**") on a select portion of the acquired Nipisi properties, created as part of the transaction. The acquisitions were funded by the issuance of 30.3 million Common Shares of Tamarack, along with draws on the Company's increased borrowing base. In addition, Tamarack issued 4.9 million Common Shares in conjunction with the acquisition of Woodcote Petroleum Inc.

On December 21, 2020, Tamarack closed the Clearwater Acquisitions for a total net purchase price of $74.0 million, after deducting the proceeds from the sale of a 2% GORR on a select portion of the acquired properties. A Form 51-102F3 Material Change Report in respect of the Clearwater Acquisitions was filed on SEDAR.

On January 11, 2017, Tamarack closed the Viking Acquisition, which was a significant acquisition under Canadian securities laws. 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 a total aggregate cash consideration of $55.0 million prior to adjustments.

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

Tamarack is an oil and gas exploration and production company committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily on Charlie Lake, Clearwater and EOR plays in Alberta. Operating as a responsible corporate citizen is a key focus to ensure Tamarack delivers on its environmental, social and governance (ESG) commitments and goals.

Tamarack seeks to fully fund its capital expenditure programs and generate free funds flow, enabling debt reduction and the return of capital to shareholders, across a wide range of commodity price environments. 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 a long-term five-year-plan. 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 and 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 Charlie Lake, Clearwater and EOR player, with continued operations in the legacy Cardium play, positioned for long-term, sustainable value creation. 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 Company has assembled 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. The Charlie Lake and Clearwater assets provide exposure to some of the most economic oil plays in Western Canada with sizeable, identified inventories of future potential drilling locations that are expected to enhance free funds flow generation while supporting Tamarack's overall resiliency and sustainability. With this portfolio, combined with an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns 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 team and management 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 effectively manage such price risk through scrutinization of the various commodity markets and established 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 the value of such lands and, on that basis, it may submit a bid.

Field equipment availability has become increasingly competitive as industry activity has accelerated and Tamarack continues to gain access to it through prior agreements and contacts. Hiring and retaining technical and administrative personnel continues to be a competitive process, but Tamarack rewards existing employees and provides opportunities for new staff to participate in the equity of the Company 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 business practices that drive long-term value creation.

Employees

As at December 31, 2021, Tamarack employed 67 full time individuals, one part-time individual and made use of 16 consultants at its head office in Calgary, Alberta. The Company also employed seven full time field employees and 140 contract field operators located at various field offices in Alberta and Saskatchewan.

Economic Diversity

Tamarack has ensured economic diversity for the Company by avoiding dependence 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. It is not currently possible to quantify any such increased expenditures; however, 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*".

Demonstrated Commitment to Environment, Social and Governance Practices and Initiatives

Tamarack has shown an ongoing commitment to sustainability through integration of ESG practices across all business operations. This includes specific, measurable goals across its commitment and priority areas along with tangible initiatives that progress those goals and commitments. The Company takes pride in being a responsible steward of the environment, as well as its people, assets and capital and believes that economic growth, the well-being of society and environmental responsibility are not mutually exclusive concepts. Tamarack values its long-standing Indigenous partnerships and its corporate culture of innovation that have set the foundation for the Company's sustainability leadership.

Tamarack will continue to invest in long-term projects designed to improve operational performance, enhance sustainability and deliver positive results for stakeholders. With a focus on increased transparency, a corporate-wide ESG culture and continuous improvement of key sustainability metrics, the Company plans to move forward as a leader in responsible operations and as a wholly-accountable corporate citizen.

Across all facets of its business, Tamarack clearly demonstrates a commitment to sustainability, including investing in long-term projects that are designed to ultimately lower production decline rates, increase resiliency and help drive improved returns. A more detailed description of Tamarack's corporate reporting initiatives and a discussion of ESG issues are outlined in the Company's 2021 Sustainability Report, which is available on the Company's website 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 community consultation policy; a hedging and risk management policy; a respectful workplace policy; and a health, safety and environment policy. Tamarack's Environment, Safety and Sustainability (ES&S) committee of the Board oversees internal ESG milestones as well as all aspects of health, safety, environmental protection and sustainability. Additional information relating to these policies and milestones 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 25, 2022. The effective date of the Statement is December 31, 2021 and the preparation date of the Statement is January 18, 2022. In compliance with the requirements of NI 51-101, tables below provide the reserves disclosure for Tamarack as at December 31, 2021, 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, NGL 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, NGL 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, NGL 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, NGL 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, 2021 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, 2021

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)	Conven-tional Natural Gas Gross (MMcf)[(2)]	Conven-tional Natural Gas Net (MMcf)[(2)]	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gross (MBoe)	Total Net (MBoe)
Proved:										
Developed Producing	26,322	21,496	4,093	3,487	114,981	104,619	6,712	5,551	56,290	47,971
Developed Non-Producing	1,242	1,089	0	0	5,053	4,567	255	200	2,339	2,051
Undeveloped	25,690	21,568	4,188	3,765	69,461	63,461	4,049	3,385	45,504	39,295
Total Proved	53,253	44,153	8,281	7,252	189,495	172,647	11,016	9,136	104,133	89,316
Probable	40,856	32,806	7,819	6,644	128,681	117,187	7,677	6,232	77,799	65,214
Total Proved plus Probable	94,110	76,960	16,100	13,896	318,177	289,833	18,692	15,369	181,932	154,531

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, 2021 DISCOUNTED AT % PER YEAR[(2)(3)]

FORECAST PRICES AND COSTS

Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)	Unit Value Before Tax Discounted at 10%/Year[(1)] ($/Boe)	Unit Value Before Tax Discounted at 10%/Year[(1)] ($/Mcfe)
Proved:							
Developed Producing	1,261,988	1,121,358	1,008,539	919,330	847,794	21.02	3.50
Developed Non-Producing	58,418	48,404	40,960	35,369	31,072	19.97	3.33
Undeveloped	1,045,941	799,826	625,970	500,594	407,702	15.93	2.66
Total Proved	2,366,347	1,969,587	1,675,469	1,455,293	1,286,568	18.76	3.13
Probable	2,344,259	1,677,816	1,278,008	1,019,532	841,347	19.60	3.27
Total Proved plus Probable	4,710,606	3,647,403	2,953,476	2,474,825	2,127,915	19.11	3.19

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, 2021 DISCOUNTED AT (%/YEAR)(1)(2)(3)

FORECAST PRICES AND COSTS

Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)	Unit Value After Tax Discounted at 10%/Year(1) ($/Boe)	Unit Value After Tax Discounted at 10%/Year(1) ($/Mcfe)
Proved:							
Developed Producing	1,162,064	1,032,484	928,439	846,344	780,684	19.35	3.23
Developed Non-Producing	45,710	37,574	31,548	27,054	23,625	15.38	2.56
Undeveloped	803,862	604,182	463,513	362,753	288,694	11.80	1.97
Total Proved	2,011,635	1,674,241	1,423,499	1,236,151	1,093,003	15.94	2.66
Probable	1,813,250	1,287,994	974,511	773,116	635,033	14.94	2.49
Total Proved plus Probable	3,824,885	2,962,235	2,398,010	2,009,268	1,728,036	15.52	2.59

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, 2021

FORECAST PRICES AND COSTS

Reserves Category	Revenue ($000)	Royalties ($000)	Operating Costs ($000)	Capital Development Costs ($000)	Abandonment & Reclamation Costs ($000)	Future Net Revenue Before Income Tax ($000)	Income Tax ($000)	Future Net Revenue After Income Tax ($000)
Total Proved	5,935,389	921,110	1,817,375	623,515	207,042	2,366,347	354,712	2,011,635
Total Proved plus Probable	10,739,157	1,774,153	3,041,921	965,626	246,851	4,710,606	885,721	3,824,885

FUTURE NET REVENUE BY PRODUCTION TYPE AS OF DECEMBER 31, 2021

FORECAST PRICES AND COSTS

Reserves 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]	1,391,063	20.11	3.35
	Heavy Oil[1]	244,857	31.41	5.23
	Conventional Natural Gas[3]	39,548	3.20	0.53
	Total	1,675,469	18.76	3.13
Proved plus Probable	Light and Medium Oil[1][2]	2,430,073	20.30	3.38
	Heavy Oil[1]	455,368	30.43	5.07
	Conventional Natural Gas[3]	68,035	3.42	0.57
	Total	2,953,476	19.11	3.19

Notes:
(1) Values include solution gas and other by-products.
(2) Category includes immaterial tight oil volumes.
(3) Values include by-products but exclude 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 record(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, 2021 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, 2021 were $78.64/Bbl for light and medium crude oil, $64.56/Bbl for heavy oil, $41.77/Bbl for NGL and $3.70/Mcf for natural gas. The average realized price on a total oil equivalent basis was $55.38/Boe.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2021

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										
2022	72.83	86.82	75.22	66.46	3.56	43.39	57.49	91.85	0.00	0.7967
2023	68.78	80.73	69.92	61.90	3.20	35.92	50.17	85.53	2.30	0.7967
2024	66.76	78.01	67.26	59.44	3.05	34.62	48.53	82.98	2.00	0.7967
2025	68.09	79.57	68.60	60.64	3.10	35.31	49.50	84.63	2.00	0.7967
2026	69.45	81.16	69.98	61.87	3.17	36.02	50.49	86.33	2.00	0.7967
2027	70.84	82.78	71.37	63.10	3.23	36.74	51.50	88.05	2.00	0.7967
2028	72.26	84.44	72.80	64.38	3.30	37.47	52.53	89.82	2.00	0.7967
2029	73.70	86.13	74.25	65.67	3.36	38.22	53.58	91.61	2.00	0.7967
2030	75.18	87.85	75.49	66.68	3.43	38.99	54.65	93.44	2.00	0.7967
2031	76.68	89.60	77.00	68.02	3.50	39.77	55.74	95.32	2.00	0.7967
2032	78.21	91.40	78.54	69.38	3.57	40.56	56.86	97.22	2.00	0.7967
2033+(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		

Notes:

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

Reserves Reconciliation

The following table sets forth a reconciliation of Tamarack's TP, Probable and TPP Reserves as at December 31, 2021 against such Reserves as at December 31, 2020 based on forecast price and cost assumptions:

RECONCILIATION OF COMPANY GROSS RESERVES(1) BY PRINCIPAL PRODUCT TYPE

FORECAST PRICES AND COSTS

	Lt & Med Crude Oil Proved(2) (Mbbl)	Lt & Med Crude Oil Probable(2) (Mbbl)	Lt & Med Crude Oil Proved + Probable(2) (Mbbl)	Heavy Crude Oil Proved (MBbl)	Heavy Crude Oil Probable (MBbl)	Heavy Crude Oil Proved + Probable (MBbl)	Total Crude Oil Proved (MBbl)	Total Crude Oil Probable (MBbl)	Total Crude Oil Proved + Probable (MBbl)
December 31, 2020	30,072	24,956	55,028	3,371	2,868	6,239	33,443	27,824	61,267
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery(3)	7,323	6,492	13,815	2,919	1,838	4,757	10,242	8,330	18,573
Technical Revisions	(3,561)	(8,091)	(11,652)	255	(534)	(279)	(3,306)	(8,625)	(11,931)
Acquisitions	24,817	17,456	42,273	3,415	3,651	7,066	28,232	21,106	49,339
Dispositions	(196)	(75)	(270)	0	0	0	(196)	(75)	(270)
Economic Factors	518	118	636	4	(4)	0	522	114	636
Production	(5,720)	0	(5,720)	(1,684)	0	(1,684)	(7,403)	-	(7,403)
December 31, 2021	53,253	40,856	94,110	8,281	7,819	16,100	61,534	48,676	110,210

	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, 2020	6,819	4,283	11,102	141,468	91,348	232,816	63,840	47,332	111,172
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery(3)	987	853	1,840	16,436	13,540	29,976	13,969	11,440	25,409
Technical Revisions	64	(473)	(409)	(2,383)	(14,212)	(16,594)	(3,638)	(11,467)	(15,105)
Acquisitions	3,965	2,971	6,936	51,300	37,472	88,772	40,747	30,323	71,070
Dispositions	(89)	(35)	(124)	(1,590)	(644)	(2,234)	(550)	(217)	(767)
Economic Factors	513	78	591	8,072	1,177	9,249	2,380	389	2,768
Production	(1,244)	-	(1,244)	(23,807)	-	(23,807)	(12,615)	-	(12,615)
December 31, 2021	11,016	7,677	18,692	189,495	128,681	318,177	104,133	77,799	181,932

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

PUD reserves are generally those reserves related to drilling spacing units directly offsetting producing reserves where there is demonstrated geological continuity. The majority of the PUD reserves are forecast for development over the next three years. However, Tamarack has a clearly stated strategy to fully fund its capital expenditures with internally-generated adjusted funds flow. GLJ has forecasted the Company to spend approximately 53% of its TP future development capital ("**FDC**") and 42% of TPP FDC in 2022 and 2023. In 2024, 29% of the Company's TP FDC is expected to be invested, with approximately 16% remaining to be invested in the subsequent two years, while 25% of TPP FDC is expected to be spent in 2024 with approximately 31% remaining to be invested in the following two years. Tamarack expects that 99% of the FDC forecast by GLJ will be invested within five years. The Company believes this 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) (MBbl)	Crude Oil Lt. & Med. at Year-End(2) (MBbl)	Crude Oil Heavy First Attributed(1) (MBbl)	Crude Oil Heavy at Year-End (MBbl)	Conventional Natural Gas First Attributed(1)(3) (MMcf)	Conventional 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)
2019	4,567	13,497	0	170	3,842	36,979	73	1,119	5,280	20,949
2020	1,401	11,518	2,154	2,162	8,952	38,172	533	1,451	5,580	21,492
2021	16,343	25,690	3,958	4,188	33,941	69,461	2,567	4,049	28,525	45,504

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) Light and medium oil includes immaterial tight oil volumes.
(3) Conventional natural gas 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 forecasted 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)	Conventional Natural Gas First Attributed(1)(3) (MMcf)	Conventional 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)
2019	4,856	18,718	0	278	2,958	51,703	54	1,648	5,403	29,261
2020	1,947	16,582	2,300	2,306	16,088	56,235	1,312	2,635	8,240	30,895
2021	18,765	29,069	5,042	5,632	40,705	87,933	3,067	5,413	33,659	54,771

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.
(2) Light and medium oil includes immaterial tight oil volumes.
(3) Conventional natural gas 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 11 of the Company's Consolidated Financial Statements for the years ended December 31, 2021 and 2020 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 in GLJ's forecast of well abandonment and reclamation costs (this includes all active entities within active assets only); all other abandonment and reclamation costs have not been included (e.g. wells for which no reserves are assigned and for facilities and pipelines); 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)
2022	161,379	190,710
2023	169,751	219,325
2024	178,018	241,292
2025	82,307	174,643
2026	20,111	126,988
2027	3,215	0
2028	3,988	0
2029	0	3,345
2030	0	0
2031	0	0
2032	3,117	5,276
2033	0	0
Subtotal	621,886	961,578
Remainder	1,628	4,047
Total	623,515	965,626
10% Discounted	518,215	773,442

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

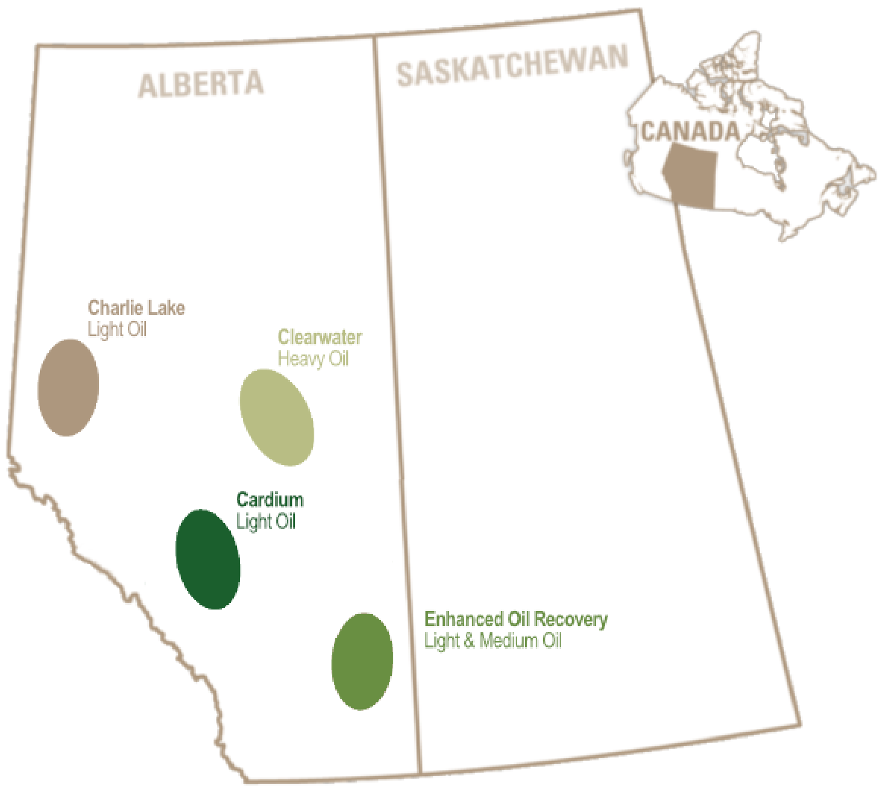
Tamarack typically has three sources of funding available to finance its capital expenditure program: internally generated adjusted funds flow, debt financing and new equity issuances. Debt financing and equity issuances are utilized when appropriate and where favourable terms are available.

The Company expects to fully fund its 2022 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 3, 2022. 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 located in the provinces of Alberta and Saskatchewan, Canada largely targeting the Charlie Lake, Clearwater and EOR plays. A summary of the important oil and natural gas properties by area as at December 31, 2021 follows. Tamarack's producing and non-producing wells by area 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 93 of this AIF.

Clearwater

2022 Capital Allocation(1)	2022 Budgeted Wells Drilled(1)	Inventory of Locations(2)	2022 Forecasted % of Production(3)
40%	92 (82.6 net)	549 (470.5 net)	25%

Notes:

(1) Details are as per the 2022 Corporate Budget Update Press Release (January 13, 2022).

(2) Inventory represents all economic locations prior to the acquisition of Crestwynd. This number will differ from other disclosures that only identify locations with less than 18-month payout at $70 WTI and $2.50 AECO.

(3) Percent represents annual average production (boe/d) which is as per the 2022 Corporate Budget Update Press Release (January 13, 2022). This number differs from the number noted from the first year production table in the reserve tables due to the incorporation of Crestwynd volumes in the 2022 annual budget production forecast.

Tamarack's highly economic Clearwater assets cover approximately 357 (313.4 net) sections of land – 300 of which have been identified as prospective for Mannville – across the Northern (Nipsi) and Southern (Jarvie) Clearwater plays. Identified as the top free funds flow oil plays in North America (Source: "Fall 2021 Energy Overview", Peters & Co. Limited (2021)), the Clearwater assets help drive Tamarack's free funds flow growth and contribute long-life oil assets to the portfolio through low decline rates, modest sustaining capital requirements and an efficient multileg lateral drilling profile. Subsequent to the Crestwynd Acquisition, Tamarack will be the largest operator in the Southern Clearwater area and a significant competitor in the larger Clearwater region. The Clearwater assets are a key focus of Tamarack's sustainability program, with the Company investing significant capital across 2021 and 2022 to implement gas conservation infrastructure and minimize emissions. These assets also contribute positively to Tamarack's decommissioning liability profile, with minimal inactive sites and a mutilleg lateral wellbore design that minimizes surface disturbance.

At year end 2021, PDP reserves of 4,423 mboe were booked to 78 (75.5 net) producing wells. TPP reserves of 17,314 mboe were also assigned to the area. Tamarack's total estimated horizontal drilling inventory is approximately 549 (470.5 net) locations.

Charlie Lake

2022 Capital Allocation(1)	2022 Budgeted Wells Drilled(1)	Inventory of Locations(2)	2022 Forecasted % of Production(3)
30%	14 (13.7 net)	247 (246.4 net)	30%

Notes:

(1) Details are as per the 2022 Corporate Budget Update Press Release (January 13, 2022).
(2) Inventory represents all economic locations. This number will differ from other disclosures that only identify locations with less than 18-month payout at $70 WTI and $2.50 AECO.
(3) Percent represents annual average production (boe/d) which is as per the 2022 Corporate Budget Update Press Release (January 13, 2022).

Tamarack's Charlie Lake assets cover approximately 357 (326.5 net) sections of land in the northwestern area of Alberta with more than ten years of drilling locations in inventory. The Charlie Lake light oil asset economics are driven by high productivity wells and significant adjusted funds flow generation in the first year. As one of the top three free funds flow oil plays in North America (Source: "Fall 2021 Energy Overview", Peters & Co. Limited (2021)), the Charlie Lake play enables positive portfolio balance with its quick payout ratios and promising profit to investment ratios. These assets contribute positively to the sustainability profile of the organization through highly efficient operations that minimize GHG emissions.

At year end 2021, PDP reserves of 10,827 mboe were booked to 82 (75.1 net) producing wells. TPP reserves of 55,780 mboe were also assigned to the area. Tamarack's total estimated horizontal drilling inventory is approximately 247 (246.4 net) locations.

EOR

2022 Capital Allocation(1)	2022 Budgeted Wells Drilled(1)	Inventory of Net Locations/Patterns(2)(3)	2022 Forecasted % of Production(4)
15%	20 (20.0 net)	93 (87.0 net)	15%

Notes:

(1) Details are as per the 2022 Corporate Budget Update Press Release (January 13, 2022).
(2) EOR patterns vary by field but are most frequently represented by a producer-injector pair
(3) Inventory represents all economic locations. . This number will differ from other disclosures that only identify locations or patterns with less than 18-month payout at $70 WTI and $2.50 AECO. See "Presentation of Oil and Gas Information – Drilling Locations".
(4) Percent represents annual average production (boe/d) which is as per the 2022 Corporate Budget Update Press Release (January 13, 2022).

Tamarack's EOR portfolio includes a diverse set of assets across Alberta representing a wide range of formations and production types. Tamarack's key assets with production currently under waterflood include the Veteran Viking (Light Oil), Eyehill Sparky (Medium Oil) and Penny Barons (Light Oil) oil plays. In addition to these key assets, Tamarack is also exploring the feasibility of waterflood in the Nipsi Clearwater area. The Company's first pilot project was commenced in the fourth quarter of 2021 and is expected to continue through the first half of 2022. The Company also acquired a small Slave Point light oil waterflood in the Nipisi area in 2021.

The significant strategic value in EOR assets in Tamarack's portfolio is driven by the low decline and high estimated ultimate reserve recoveries. While these EOR projects require significant water utilization, Tamarack has focused on innovating in waterflooded areas to minimize freshwater consumption, including recycling of produced water, utilization of non-fresh water source wells for injection make-up water and employing joint infrastructure to supply non-fresh water to area completion operation.

At year end 2021, PDP reserves of 11,290 mboe were booked to 158 (157.9 net) producing wells. TPP reserves of 38,677 mboe were also assigned to the area. Tamarack’s total estimated waterflood pattern inventory is approximately 93 (87.0 net) locations.

Cardium & Other

2022 Capital Allocation(1)	2022 Budgeted Wells Drilled(1)	Inventory of Locations(2)	2022 Forecasted % of Production(3)
15%	0 (0.0 net)	655 (581.1 net)	30%

Notes:

(1) Details are as per the 2022 Corporate Budget Update Press Release (January 13, 2022).

(2) Inventory represents all economic locations. This number will differ from other disclosures that only identify locations with less than 18 month payout at $70 WTI and $2.50 AECO.

(3) Percent represents annual average production (boe/d) which annual average production is as per the 2022 Corporate Budget Update Press Release (January 13, 2022).

Tamarack also maintains a legacy asset base of Cardium, Viking primary and other oil and gas plays to support base production while providing portfolio diversity and inventory optionality to sustain future free funds flow generation in a myriad of market, operational and environmental conditions. Capital allocated under this asset group includes the completion of wells drilled in 2021, facility upgrades, ESG initiatives, and abandonment, remediation and reclamation programs.

At year end 2021, PDP reserves of 29,730 mboe were booked to 1,509 (1,160.5 net) producing wells. TPP reserves of 70,120 mboe were also assigned to the area. Tamarack’s total estimated horizontal drilling inventory is approximately 655 (581.1 net) locations.

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, 2021.

Area	Crude Oil Producing (Gross)	Crude Oil Producing (Net)	Crude Oil Non-prod(2) (Gross)	Crude Oil Non-prod(2) (Net)	Natural Gas Producing (Gross)	Natural Gas Producing (Net)	Natural Gas Non-prod(2) (Gross)	Natural Gas Non-prod(2) (Net)
Clearwater(3)	82	79.5	6	6.0	-	-	3	2.3
Charlie Lake	89	83.6	34	29.1	13	7.8	56	37.0
EOR	452	444.9	84	77.8	2	2.0	23	22.9
Cardium and Other	794	678.6	757	652.1	960	697.4	943	692.8
Total	1,417	1,286.6	881	765.0	975	707.2	1,025	754.9

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.

(3) Clearwater drilling involves multileg horizontal wells. One individual location may have up to 8 lateral legs. For the purposes of this table, each wellbore is counted as one well with multiple well events or legs included.

Developed and Undeveloped Lands

Province	Undeveloped Acres (Gross)	Undeveloped Acres (Net)	Developed Acres (Gross)	Developed Acres (Net)	Total Acres (Gross)	Total Acres (Net)
Alberta	1,042,384	877,942	654,407	528,694	1,696,791	1,406,636
Saskatchewan	22,914	21,798	120,157	104,590	143,071	126,389
Total	1,065,298	899,740	774,564	633,284	1,839,862	1,533,025

Tamarack had 1,065,298 gross (899,740 net) acres of undeveloped land as at December 31, 2021 located in Alberta and Saskatchewan. The Company currently has work commitments scheduled on a portion of these lands as a part of the 2020 and 2021 GORR sales. Of the initial aggregate capital commitments of $200.0 million, $99.2 million had been incurred at December 31, 2021, with remaining commitments of $43.0 million and $57.8 million to be spent in 2022 and 2023 respectively. Tamarack has leases on 216,793 net acres that expire in 2022. Tamarack expects 97,147 net acres of the expiring lands to be extended through drilling activities or leaseholder extensions. The remaining 119,646 net acres that are expected to expire in 2022 are not material to Tamarack's short- or long-term plan. 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. The number of leases that this applies to is immaterial to the Company's land position.

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, 2021 can be found in note 5 of the Notes to the Consolidated Financial Statements for the years ended December 31, 2021 and 2020.

Tax Horizon

Tamarack was not required to pay income taxes during the year ended December 31, 2021. As a result of commodity price strength, accretive acquisitions in 2021 and a strategic focus on the generation of free funds flow, Tamarack estimates that it will be required to pay income taxes during 2022.

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, 2021.

Expenditures for the Year Ended December 31, 2021	Amount ($000)
Property acquisition costs – Unproved properties [(1)]	9,065
Property acquisition costs – Proved properties	95,445
Property disposition costs – Proved properties	(46,217)
Corporate acquisition costs	360,811
Exploration costs [(2)]	3,595
Development costs [(3)(4)]	177,482
Other	1,017
Total	601,198

Notes:

(1) Property acquisition of unproved properties includes the cost of land acquired and non-producing lease rentals on those lands.
(2) Exploration costs include geological and geophysical capital expenditures and drilling costs for exploration wells.
(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(4) Development costs are 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, 2021.

Type of Well	Development Wells (Gross)	Development Wells (Net)
Light and Medium Oil	53.0	53.0
Heavy Oil	43.0	40.0
Natural Gas	2.0	0.8
Service	8.0	8.0
Dry and Abandoned	1.0	1.0
Stratigraphic Test	-	-
Total	107.0	102.8

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)	2021	2020	2019	3-Year Average
Proved Reserves				
Finding, development and acquisition cost	22.79	9.73	18.68	19.86
Finding and development costs	14.66	18.71	18.10	16.33
Acquisition costs	25.36	9.15	50.57	21.47
Proved plus Probable Reserves				
Finding, development and acquisition cost	15.10	6.90	21.64	14.31
Finding and development costs	8.74	8.32	20.97	14.71
Acquisition costs	16.28	7.15	52.13	14.23

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 PUD 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) Costs include 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, 2021, 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					
Clearwater Oil Area	-	6,032	2,461	22	6,464
Charlie Lake Oil Area	6,727	-	19,833	1,624	11,656
Other	11,110	-	41,714	1,986	20,048
Total	17,836	6,032	64,008	3,632	38,168
Total Proved plus Probable					
Clearwater Oil Area	-	7,759	2,859	26	8,262
Charlie Lake Area	8,539	-	23,905	1,957	14,480
Other	12,320	-	43,442	2,046	21,607
Total	20,859	7,759	70,206	4,029	44,349

Notes:

(1) Light and medium crude oil includes immaterial tight oil volumes.
(2) Conventional natural gas includes immaterial coal bed methane volumes.
(3) Columns may not add due to rounding.

2021 Production History

The following tables disclose, on a quarterly basis for the year ended December 31, 2021, 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 31/21	3 Months Ended Jun 30/21	3 Months Ended Sep 30/21	3 Months Ended Dec 31/21	12 Months Ended Dec 31/21
Average Daily Production[(1)]					
Light and Medium Oil (Bbl/d)	10,120	14,534	19,405	18,487	15,670
Heavy Oil ($/Bbl)	2,654	4,701	5,438	5,616	4,613
Natural Gas (Mcf/d)	52,466	60,887	72,935	74,291	65,226
NGL (Bbl/d)	2,420	3,032	4,257	3,899	3,408
Total (Boe/d)	23,939	32,415	41,256	40,384	34,562
Average Net Production Prices Received					
Light and Medium Oil ($/Bbl)	64.01	75.30	79.12	88.59	78.64
Heavy Oil ($/Bbl)	48.00	61.20	67.97	71.69	64.56
Natural Gas ($/Mcf)	3.15	2.77	3.44	5.09	3.70
NGL ($/Bbl)	37.17	39.57	33.67	55.09	41.77
Total ($/Boe)	43.02	51.55	55.73	65.21	55.38
Royalties Paid					
Light and Medium Oil ($/Bbl)	7.36	11.10	14.02	14.41	12.40
Heavy Oil ($/Bbl)	5.22	5.55	8.63	6.79	6.80
Natural Gas ($/Mcf)	0.28	0.35	0.33	0.41	0.35
NGL ($/Bbl)	10.62	8.22	6.39	12.44	9.28
Total ($/Boe)	5.37	7.20	8.97	9.50	8.10
Operating Costs[(2)(3)(4)]					
Light and Medium Oil ($/Boe)	16.16	16.80	14.50	14.59	15.32
Heavy Oil ($/Bbl)	3.52	3.93	3.69	4.87	4.09
Natural Gas ($/Mcfe)	1.10	0.74	0.72	0.96	0.87
NGL ($/Boe)	-	-	-	-	-
Total ($/Boe)	9.63	9.50	8.59	9.11	9.13
Transportation Costs[(4)]					
Light and Medium Oil ($/Boe)	1.08	0.69	1.33	1.31	1.14
Heavy Oil ($/Bbl)	2.60	3.38	4.19	2.37	3.20
Natural Gas ($/Mcfe)	0.36	0.23	0.36	0.41	0.36
NGL ($/Boe)	-	-	-	-	-
Total ($/Boe)	1.54	1.24	1.91	1.54	1.62
Netback Received					
Light and Medium Oil ($/Bbl)	39.40	46.71	49.27	58.28	49.79
Heavy Oil ($/Bbl)	36.67	48.34	51.46	57.67	50.47
Natural Gas ($/Mcf)	1.42	1.45	2.02	3.31	2.12
NGL ($/Bbl)	26.55	31.36	27.28	42.65	32.49
Total ($/Boe)	26.49	33.61	36.26	45.07	36.53

Notes:

(1) Production volume noted is before the deduction of royalties.

(2) Operating 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 NGL 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, 2021 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)
Clearwater Oil Area	-	4,430	436	5	4,515
Charlie Lake Oil Area	4,543	-	12,620	1,009	7,655
Other	11,127	183	52,170	2,394	22,392
Total	15,670	4,613	65,226	3,408	34,562

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 3, 2022, there are 433,692,620 Common Shares and no Preferred Shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attached to such securities.

Common Shares

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

Preferred Shares, Issuable in Series

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

Corporate Credit Ratings

As at December 31, 2021, the Company had not received a corporate credit rating but had begun the process to pursue a rating. Subsequent to year end, Tamarack received both an issuer credit rating and a senior-unsecured sustainability linked note rating. Credit ratings received as of the date of this AIF are summarized below.

	S&P Global Ratings ("S&P")
Issuer Credit Rating	B
Senior Unsecured Sustainability-Linked Notes	B+

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt rated ''B'' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings affect the Company's ability to obtain short-term and long-term debt and equity financing and the cost of such financing. A reduction in the current credit ratings by the rating agencies, particularly a downgrade below the current ratings or a negative change in the ratings outlook, could adversely affect Tamarack's cost of financing and access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability, and the associated costs, to: (i) enter into ordinary course derivative or hedging transactions and may require the posting of additional collateral under contracts; and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

The credit ratings accorded to Tamarack by S&P are not recommendations to purchase, hold or sell any of our securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

Tamarack made payments to S&P in connection with the assignment of ratings to both our long-term debt and the Company and may make payments to S&P in the future in connection with the confirmation of such ratings in the future. In addition, Tamarack made payments to S&P for a second party-opinion of the SLB Framework that the SLB offering was founded on.

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, 2021 and as at March 3, 2022:

Month	High ($)	Low ($)	Volume
January 2021	1.52	1.25	28,939,217
February 2021	2.38	1.32	66,219,525
March 2021	2.46	1.99	85,973,382
April 2021	2.61	2.16	48,199,549
May 2021	2.83	2.37	43,104,174
June 2021	2.90	2.42	64,601,040
July 2021	2.75	2.05	60,652,858
August 2021	2.73	2.07	46,977,715
September 2021	3.31	2.39	72,859,692
October 2021	3.75	3.19	60,400,388
November 2021	3.95	3.31	64,894,760
December 2021	3.91	3.08	81,961,307
January 2022	4.96	3.90	83,008,820
February 2022	5.26	4.60	69,337,413

Prior Sales

Option Grants

During the financial year ended December 31, 2021, the Company granted an aggregate of 867,500 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 9, 2021	592,500	$2.25
June 9, 2021	110,000	$2.66
August 16, 2021	110,000	$2.32
September 7, 2021	55,000	$2.53
Total Issued:	867,500	$2.33

Note:

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

Except as set forth below, no additional unlisted securities of the Company were issued during the financial year ended December 31, 2021.

RSU Grants

In the year ended December 31, 2021, the Company granted an aggregate of 2,185,937 RSUs pursuant to the PRSU Plan. As of December 31, 2021, there were 4,703,444 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.

PSU Grants

In the year ended December 31, 2021, the Company granted an aggregate of 2,162,400 PSUs pursuant to the PRSU Plan. As of December 31, 2021, there were 4,873,672 PSUs outstanding. 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.

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). During 2021, all outstanding TAC Preferred Shares were exchanged for a total of 307,025 Common Shares and $79,456.32 in cash to accommodate the amalgamation of TAC into TVE. As at December 31, 2021, there were no TAC Preferred Shares outstanding.

DIVIDENDS

On January 13, 2022, the Board declared its first monthly cash dividend of C$0.0083 per Common Share payable on February 15, 2022 to shareholders of record at the close of business on January 31, 2022. Prior to such time, Tamarack had never declared or paid any cash dividends on the Common Shares.

Tamarack's intention will be to pay monthly cash dividends on the Common Shares from its free funds flow (funds flow less total capital expenditures, including exploration and production capital and other corporate expenditures and excluding acquisition and core disposition activities, and is prior to dividend payments) to shareholders of record as of the dividend record date which is usually approximately 15 days prior to the dividend payment date. Tamarack's dividend policy is intended to provide shareholders with relatively stable and predictable monthly dividends, while retaining a portion of free cash flow to provide the Company with the financial flexibility to either reduce corporate debt, modify the development plan or pursue strategic acquisitions, as deemed appropriate.

In determining the level of dividends to be declared, the Board takes into consideration such factors as current and expected future levels of free funds flow (including income tax), capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors. Over the long term, Tamarack expects to continue to pay dividends from its free funds flow; however, credit facilities may be used to stabilize dividends from time to time. Growth capital expenditures will be funded from retained cash flow from operating activities, proceeds from asset dispositions and proceeds from additional debt or equity, as required. Although Tamarack intends to continue to make regular monthly dividends to shareholders, dividends are not guaranteed.

Notwithstanding the foregoing, the amount of future cash dividends declared and paid by Tamarack, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Tamarack is a party from time to time (including, without limitation, the agreements governing Tamarack’s credit facilities and senior notes), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review this policy on a monthly basis. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and Tamarack's management team, the Board may change this policy following any such monthly review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends being reduced or suspended entirely.

The Board intends dividends declared and paid by Tamarack will qualify as "eligible dividends" for the purposes of the Income Tax Act (Canada) (and any similar applicable provincial legislation), and thus qualify for the enhanced gross-up and tax credit regime available to certain shareholders. The Board therefore intends to designate dividends paid by Tamarack as "eligible dividends" and notify shareholders that dividends are "eligible dividends" for these purposes by posting a general notice to this effect on Tamarack's website and by disclosing this fact in each press release that Tamarack issues that contains a dividend announcement. Notwithstanding the foregoing, no assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

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
John Rooney(1)(3)(4) *Calgary, Alberta, Canada*	Chairman of the Board Director since March 2021	Mr. Rooney is a Calgary-based entrepreneurial executive with a technical background in finance and is Chairman of Kara Technologies Inc, an organization dedicated to the development of technology for the economic production of low emissions fuels. Prior thereto, he founded and ran a number of public oil and gas companies, holding various executive roles. Mr. Rooney brings exceptional value to the Tamarack Board of Directors through his more than 20 years of public, private and not-for-profit directorships. Mr. Rooney is a Chartered Accountant and a Chartered Business Valuator.
Jeffrey Boyce(1)(4) *Calgary, Alberta, Canada*	Director since October 2013	Mr. Boyce is a senior oil and gas executive with 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. He has previously co-founded and operated publicly-traded oil and gas companies and served as a director for both junior and intermediate producers.
Ian Currie(2)(4) *Okotoks, Alberta, Canada*	Director since March 2017	Mr. Currie is a professional engineer and 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 held executive and senior operational roles with two different energy companies.
John Leach(1)(2) *Calgary, Alberta, Canada*	Director since January 2017	Mr. Leach is a Chartered Professional Accountant (CPA) and 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 and executive of Baytex Energy Ltd. since 1993 and has been a CPA since 1991.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Marnie Smith(1)(3) *Calgary, Alberta, Canada*	Director since April 2020	Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she has led the Western Canadian team and Canadian energy platform and has been a member of the Global Industrial and Natural Resources and Financial Services practices since October 2021. Prior thereto, she served as Senior Client Partner with Korn Ferry from September 2017 and as Managing Director & Head of Canadian Energy at Macquarie Group
Brian Schmidt *Calgary, Alberta, Canada*	President and Chief Executive Officer Director since June 2010	President and Chief Executive Officer of the Company and Founder of its privately-held predecessor since 2009. Mr. Schmidt is also an Honorary Chief of the Blood Tribe. He is currently a director on the Board of Governors of the Canadian Association of Petroleum Producers where he is the Indigenous Policy Group Chairman. He is also an advisor to the Indian Oil & Gas Co-Management Board, assisting First Nations with policy development. He is also on the board of The Explorers and Producers Association of Canada.
Robert Spitzer(2)(3) *Bragg Creek, Alberta, Canada*	Director Since June 2017	Mr. Spitzer is an experienced professional in the upstream oil and gas field. Mr. Spitzer is currently an independent businessman and previously served as Executive Vice President of Apache Kitimat Upstream from 2013-2015 and Vice President New Ventures of Apache Canada Ltd. from 2005-2012. Prior thereto, Mr. Spitzer held a variety of exploration and development-based positions with U.S.-based and international oil and gas companies.
Steve Buytels *Calgary, Alberta, Canada*	Vice President, Finance & CFO	Mr. Buytels joined Tamarack in 2020 and has oil and gas capital markets, finance and advisory industry experience. Prior to joining Tamarack, he held Managing Director, Principal or similar roles in equity and debt capital markets with independent investment dealers..
Kevin Screen *Calgary, Alberta, Canada*	Chief Operating Officer	Mr. Screen is a professional engineer and has been COO of the Company since July 2021. Prior thereto, he held the role of VP, Production and Operations since September 2011. Before joining Tamarack, he held leadership and technical positions with the Canadian arm of a U.S. based producer since 2002.
Christine Ezinga *Calgary, Alberta, Canada*	Vice President, Corporate Planning & Business Development	Ms. Ezinga joined the Company in 2021 in her current role and brings diverse capital markets experience in finance, investor relations and business development with several Canadian oil and gas producers.

Name, Municipality of Residence	Position with the Company	Principal Occupation During the Past 5 Years
Martin Malek *Calgary, Alberta, Canada*	Vice President, Engineering	Mr. Malek has been with Tamarack since April 2014. He has significant oil and gas experience from positions held in Production, Operations and Field Development. Mr. Malek is a graduate of the University of Calgary holding a BSc in Chemical Engineering and is a member of the Association of Professional Engineers and Geoscientists.
Scott Reimond *Calgary, Alberta, Canada*	Vice President, Exploration	Mr. Reimond was appointed Vice President, Exploration of the Company in October 2012. He had previously been the Exploration Manager of the Company and its privately-held predecessor since 2009. Previously, he was a Geologist at several growth-oriented oil and gas producers.
Scott Shimek *Calgary, Alberta, Canada*	Vice President, Production & Operations	Mr. Shimek joined Tamarack in 2021 bringing significant experience in the energy industry, having integrated his diverse technical knowledge into various leadership roles. He holds a BSc in Mechanical Engineering (Distinction) from the University of Alberta and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.
Sony Gill *Calgary, Alberta, Canada*	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) Director is a member of the Board of Directors' audit committee.
(2) Director is a member of the Board of Directors' reserves committee.
(3) Director is a member of the Board of Directors' corporate governance and compensation committee.
(4) Director is a member of the Board of Directors' environment, safety and sustainability committee.

As of March 3, 2022, 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 10,125,446 Common Shares, representing approximately 2.33% 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 John Leach, Jeffrey Boyce, Marnie Smith and John Rooney, 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

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 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.

Marnie Smith

Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she has led the Western Canadian team and Canadian energy platform and has been a member of the Global Industrial and Natural Resources and Financial Services practices since October 2021. Prior thereto, she served as Senior Client Partner with Korn Ferry from September 2017 and as Managing Director & Head of Canadian Energy at Macquarie Group, practicing in the upstream, midstream and energy services sectors from 2004. Ms. Smith brings extensive experience working with North American and global energy companies' executives and boards through the delivery of strategic and M&A advice; financing solutions; corporate and asset valuation; and transaction evaluation, execution and negotiations.

She holds a Bachelor of Commerce (Distinction) and a Bachelor of Arts, International Relations (Distinction) from the University of Calgary, as well as a Master of Finance from INSEAD.

John Rooney

Mr. Rooney is a Calgary-based entrepreneurial executive with a technical background in finance and is Chairman of Kara Technologies Inc, an organization dedicated to the development of technology for the economic production of low emissions fuels. Prior thereto, he founded and ran a number of public oil and gas companies, holding various executive roles. Mr. Rooney brings exceptional value to the Tamarack Board of Directors through his more than 20 years of public, private and not-for-profit directorships. Mr. Rooney is a Chartered Accountant and a Chartered Business Valuator.

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, and which result in aggregate annual non-audit fees of less than $50,000 at completion, 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	2021	2020
Audit fees[(1)]	699,245	369,685
Audit-related fees[(2)]	-	-
Tax fees[(3)]	37,840	-
All other fees[(4)]	-	-
Total fees	$737,085	$369,685

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 regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of crude oil and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. While 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, investors should consider such legislation, regulations and agreements carefully. 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, but regional market and transportation issues also influence prices. Specific prices that a producer receives will 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.

Global oil markets have recovered significantly from the price drops resulted from the COVID-19 pandemic. After a meaningful recovery in 2021, oil prices in the first quarter of 2022 have risen to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2022, despite newly emerging COVID variants, expected interest rate increases in major economies and other uncertainties with respect to the world economy.

In November 2021, Russia began to amass troops along the Ukrainian border, heightening military tensions in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine. Ongoing military tensions between Russia and Ukraine have the potential to threaten the supply of oil and gas from the region. The long-term impact of the tensions between these nations on the global economy and energy commodity pricing remains uncertain. See "*Risk Factors – Impact of the COVID-19 Pandemic and Risks Related Thereto*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Natural Gas Liquids

The pricing of condensates and other NGL such as ethane, butane, propane and pentanes sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. 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, availability of, and access to, liquids fractionation, 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 of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Exports from Canada

In the summer of 2019, the National Energy Board ("**NEB**") was replaced with the Canadian Energy Regulator ("**CER**"). The CER's governing legislation is the Canadian Energy Regulator Act ("**CERA**") and the Impact Assessment Act ("**IAA**").The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada.

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**") until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licenses, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

Transportation Constraints, Pipeline Capacity and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL is the deficit of transportation capacity to transport production from Western Canada to the U.S. and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part 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.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. 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 and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved they often face delays due to actions taken by provincial and municipal governments, public interest groups and 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.

Specific Pipeline Updates

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Inc's ("**Enbridge**") Line 3 Replacement Project (the "**Line 3 Replacement**") from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, experienced permitting difficulties in the United States and completion of the United States portion of the pipeline replacement was delayed following the announcement that the Minnesota Pollution Control Agency would require a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals declared that the Minnesota Utilities Commission correctly granted Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court refused to hear an appeal on this matter.

After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government completed a purchase of 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 federal Court of Appeal quashed the approval and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and the Supreme Court of Canada ("**SCC**") in July 2020.

In addition, on April 25, 2018, the Government of British Columbia submitted a reference question to the British Columbia Court of Appeal, asking whether it has the constitutional jurisdiction to amend the Environmental Management Act to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal unanimously answered the reference question in the negative. On January 16, 2020, the SCC unanimously dismissed the Attorney General of British Columbia's appeal.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and it is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a state lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan. In November of 2021, a

Federal judge ruled that the lawsuit should be heard in federal court by U.S. District Judge Janet Neff, who retained jurisdiction over a separate case brought by Enbridge over the November 2020 shutdown order. The Attorney General and Governor of Michigan argue that Line 5's presence in the Straits violates the public trust and state environmental law. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act (the "**OTMA**"), which imposes a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

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/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices.

In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of February 2022, no permanent rules have been approved.

Natural Gas and LNG

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 infrastructure 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 is generally lower than the prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**") to prioritize deliveries into storage (temporary service protocol). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER which was sent to the federal Cabinet for approval. Following the effects of COVID-19, the Governor in Council ("**GIC**") extended the legislative timeline for consultation with Indigenous groups which extended the decision date to no later than May 2021. On April 30, 2021, the GIC approved the issuance of the certificate of public convenience by the CER.

In July 2020, the Explorers and Producers Association of Canada applied to extend the temporary service protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal 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 joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the CGL Pipeline). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline. The CGL Pipeline is currently 50% completed and is slated to be completed in 2023.

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, a subsidiary of Woodside Petroleum Ltd. However, both partners are looking to sell some or all of their interest in the project. In March 2021, both parties ceased funding further feasibility work for the proposed Kitimat LNG Project. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia, and owned by Woodfibre LNG Limited a subsidiary of Singapore-based Pacific Oil and Gas Ltd. The BC Oil and Gas Commission ("**BC Commission**") approved a project permit for the Woodfibre LNG Project, in July 2019. Pre-installation work for the Woodfibre LNG Project is planned for early 2022 and intended to gradually ramp up to September 2023, when major construction is targeted to begin. Substantial completion is expected in Q3 2027. GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a 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 in Québec. The Énergie Saguenay Project is currently slated for completion in 2026. Pieridae Energy Ltd.'s (Pieridae) proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has a downstream agreement with Uniper, a German utility, for all of the LNG produced at Goldboro's train. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae decided in July 2021 not to proceed with the project. Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**"). On June 8, 2021 the Haisla First Nation and Pembina Pipeline Corporation announced a partnership agreement whereby Pembina Pipeline Corporation will become the Haisla Nation's partner in the development of the Cedar LNG Project. Ksi Lisims LNG project, owned by Nisga's Lisims Government, Rockies LNG Partners and Western LNG is currently in the environmental assessment stage, with the BC EAO conducting the environmental assessment on behalf of the IA Agency. Construction is anticipated to begin in 2024 with the site operational in late 2027 or 2028.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system transporting crude oil. The changes that Enbridge wished to implement included the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. 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 approval of the proposed service and tolling framework. On November 26, 2021, the CER issued its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90% of the Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from eight to 20 years. Contracts for firm service were to be awarded through an open season process put forward as part of the application.

Curtailment

December 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. Under the Curtailment Rules, as amended, the Government of Alberta can, on a monthly basis, require crude oil and crude bitumen producers producing more than 20,000 bbl/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

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 and was set at 3.81 million bbl/d through 2020. The Curtailment Rules, which were set to be repealed on December 31, 2020, were extended to December 31, 2021. On December 9, 2021, the Government of Alberta announced that the provincial policy on restraining oil production, a strategy to reduce price-depressing gluts, would end December 31, 2021.

The United States Mexico Canada Agreement and Other Trade Agreements

*NAFTA/*USMCA

The North American Free Trade Agreement (“**NAFTA**”) that previously existed among the governments of Canada, the United States and Mexico has been replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement ("**USMCA**"), and sometimes referred to as the Canada United States Mexico Agreement, or ("**CUSMA**"). The USMCA came into force on July 1, 2020. Because 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 USMCA could have an impact on Western Canada’s petroleum and natural gas industry at large, including the Company's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

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. The CPTPP is in force among the first seven countries to ratify the agreement: Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

Canada has also pursued a number of other international free trade agreements with countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. 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 crude oil and natural gas products to the European Union. Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union (Brexit) on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CPTPP, CUKTCA 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.

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 rights 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.

Each of the provinces in Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. In addition, 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. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown. Such reversionary rights may impact any GORR Interests granted out of Crown leases.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners, such as the Company. Rights to explore for and produce privately-owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

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 the exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, crude 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.

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 in addition to applicable federal and provincial taxes and 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 production. 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 volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low. The incentive programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Producers and working interest owners of oil and natural gas rights may also create 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, the terms of which are subject to negotiation.

Alberta

In Alberta, provincially set royalty rates apply to Crown-owned mineral rights and crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis.

In January 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 four 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. Crown royalties payable on the production of crude oil and natural as are paid on a well-by-well basis. Producers of crude oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis. 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. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a 5-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40 to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan also has a drilling incentive whereby qualifying incentive volumes of newly drilled oil wells are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced.

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 freehold mineral 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), Freehold Mineral Taxes or production taxes are levied on the production of crude oil and natural gas from freehold lands in each of the Western Canadian provinces 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.

Where crude oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers and collecting and distributing royalty revenues. 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 royalty rate for each lease.

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 (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**CO_2e**"), 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. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails, 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. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

The enactment of the CERA and IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. However, 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 fall to independent commissioners. Despite this structural change, 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.

The IAA is similar to the repealed CEAA 2012 in that it relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAA. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

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. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. The hearing wrapped up on February 26, 2021. The Alberta Court of Appeal is currently deliberating and has yet to release its decision. It is assumed that regardless of the outcome it will be appealed to the SCC.

On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada.

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 principle regulator responsible for all energy development in Alberta. It derives its authority from the *Responsible Energy Development Act* (Alberta) and a number of related statutes 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 Government of Alberta relies on regional planning to accomplish its 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. 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 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.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in Subsurface Order Nos. 2, 6 and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the Seismic Protocol Regions). Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions, and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

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 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 oversees liability management in the province. On June 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF**") that will replace the Alberta Liability Management Program ("**AB LMR Program**") and its constituent programs. The goal of the AB LMF is to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the AB LMF through legislative and AER directive amendments. New developments under the AB LMF include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**").

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in Orphan Well Association v Grant Thornton Ltd. (also known as the Redwater decision). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed Bill 12: The Liabilities Management Statutes Amendment Act (the "**LMSAA**") which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the orphan fund (the "**Orphan Fund**") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's OGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former Licensee Liability Rating Program (the "**AB LLR Program**") and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $335 million. The Government also covered $113 million in levy payments that licencees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. It is the goal that the AB LMF will assist in addressing the OWA's inventory, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF is to address five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) licencee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure. On December 1, 2021, the Government of Alberta announced amendments to Directive 006: Licensee Liability Rating ("**LLR**") Program and a new Directive 008: Licensee Life- Cycle Management. A new Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals was also introduced in April 2021 which introduces new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the AB LMF, the AB LLR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF each licencee will be required to meet mandatory annual spend targets for well closures and abandonments starting January of 2022. It is expected that the mandatory spend targets will be released in July of 2022.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target

The AER in 2015 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 applied to all inactive wells that were noncompliant with Directive 013 as of April 1, 2015. The objective was 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 licencee was required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March of 2021.

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 to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a 5-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The mix between active programs under the AB LMF and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LMF and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

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 takes on the obligation of 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 all new licensees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licensees whose deemed liabilities exceed their deemed assets (i.e., an LLR of below 1.0) are required 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 and this data is publicly available. 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.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new Financial Security and Site Closure Regulations (the "**Closure Regulations**"), which were published in June 2021, but are not yet in force. Changes under the Closure Regulations will include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees, commencing in 2023; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012, (the "**Conservation Regulations**") remain in effect until the Closure Regulations come into force. Among other things, the Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. These impacts are uncertain and it is 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 operations and cash flow. An example of a change in policy that may impact the petroleum and natural gas industry is the International Maritime Organization's implementation of a new regulation that limits the sulphur content of marine fuel oil, reducing the permissible amount of sulphur from 3.5% to 0.5%, effective January 1, 2020.

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 changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, 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. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. 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, scheduled to take place in November 2021 in Glasgow. The result of the 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre- industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in the recent Speech from the Throne (also referred to as the Throne Speech) that it may implement policy changes to exceed this target. Specific details have not yet been announced. In connection with this target, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the **"HEHE Plan**") which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. Also of relevance to the petroleum and natural gas industry, on December 21, 2021, the federal government announced that it intends to publish draft regulations that will implement a ban on the manufacture, import and sale of six categories of single-use plastics. The draft regulations are to come into force in late 2022.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Once passed, Bill C-12 will legally bind the federal government to a process to achieve net-zero emissions by 2050. The legislation will, among other things, set rolling five-year emissions-reduction targets (starting in 2030) and require plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

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 output-based pricing system for large industry (OBPS) and a regulatory fuel charge (the Fuel Charge) imposing an initial price of $20/tonne of CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. The price is set to increase to $50/tonne of CO2e on April 1, 2022.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in Reference re Greenhouse Gas Pollution Pricing Act, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Manitoba had also made an appeal to the Federal Court stating the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October of 2021, the Federal Court rejected Manitoba's argument stating the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OPBS applies in Ontario (until December 31, 2021), Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. For so long as the provincial systems in Prince Edward Island, Alberta (under the Technology Innovation and Emissions Reduction (TIER) regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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 petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the 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 natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting low carbon technologies.

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

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

The federal government has also announced that it will proceed with the development and implementation of a Clean Fuel Standard ("**CFS**") that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, the final proposed regulations will be published in late 2021 with a planned coming into force date in December 2022. The proposed CFS regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels beginning in December 2022. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the CLP). Under this strategy, the Climate Leadership Act (Alberta) (the "**CLA**") came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. 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, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the Government of Alberta repealed the CLA and the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $40/tonne of CO2e and will increase to $50/tonne on April 1, 2022. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulation.

The TIER regulation applies 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, 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. 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. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. 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. As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta aims to 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. The release of the updated 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. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

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. 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. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. On December 2, 2021, the AER released a Request for Full Project Proposals for Carbon Sequestration Hubs ("**RFPP**"). Following significant interest in carbon capture and storage, the RFPP is intended to facilitate the issuance of rights to Alberta's pore space to proponents to enable the development and operation of carbon storage hubs. The Government of Alberta is currently accepting applications for Alberta's industrial heartland region near Edmonton. Proposals are to be accepted between January 4, 2022 and February 1, 2022.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization.

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. The Government of Saskatchewan subsequently 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 and 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 on December 18, 2018, establishing the framework of an output-based emissions management framework. As noted above, the federal fuel charge applies in Saskatchewan and the system implemented by the MRGGA currently meets the federal stringency requirements for the emissions it covers and the federal backstop applies for those emissions which are not covered.

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 CO_2e 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 reduce 4.5 million tonnes of CO_2e emissions by 2025, with a total reduction of 38.2 million tonnes CO_2e 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.

In October 2019, The Oil and Gas Conservation Amendment Act was proclaimed into force. This Act, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented Directive PNG017: Measurement Requirements for Oil and Gas Operations, which came into force in December 2019 and was amended in April 2020, and Directive PNG036: Venting and Flaring Requirements, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024. The equivalency agreement terminates on or by December 31, 2024. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide $500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be increasing investment in CCUS through enhanced oil recovery CCUS projects.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In December 2020, the federal government introduced Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. Bill C-15 received royal assent and was passed into law on June 21, 2021.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and Bill C-15 are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

Accountability and Transparency

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 taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

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 adjusted funds flows and in some cases, its reputation, could be materially adversely affected.

Impact of the COVID-19 Pandemic and Risks Related Thereto

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on our business, including changes to the way we and our counterparties operate, and on our financial results and condition. The spread of the COVID-19 pandemic, given its severity and scale, continues to adversely affect our business to varying degrees and many of our customers and business partners and also continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. At the onset of the COVID-19 pandemic, governments and regulatory bodies in affected areas imposed a number of measures designed to contain the COVID-19 pandemic, including widespread business closures, social distancing protocols, travel restrictions, quarantines, curfews and restrictions on gatherings and events. While a number of containment measures have been and continue to be gradually eased or lifted across some regions, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 have been and continue to be instituted in line with guidance of public health authorities. In addition, the emergence of the second, third and fourth waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains such as the Delta strain and the Omicron strain, has led to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures continue to impact global economic activity, including the ability to move towards recovery of the global economy and such measures also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. As the impacts of the COVID-19 pandemic continue to materialize, the prolonged effects of the disruption have had and continue to have adverse impacts on our business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks.

We are closely monitoring the potential and realized effects and impacts of the COVID-19 pandemic, which continues to be a rapidly evolving situation. Uncertainty remains as to the full impacts of the COVID-19 pandemic on the global economy, commodity and financial markets, crude oil and natural gas capital investment levels in the Western Canadian Sedimentary Basin and the energy business more broadly. The ultimate impacts will depend on future developments that are highly uncertain and cannot be predicted, including the scope, severity, duration and additional subsequent waves of the COVID-19 pandemic, including the introduction of new variants, as well as the effectiveness of actions and measures taken by the various levels of government. Despite recent positive vaccine developments, the ongoing evolution of the development and distribution of effective vaccines, recommendation and availability of subsequent vaccine doses and the availability of efficient and accurate testing options also continues to raise uncertainty.

We may face challenges, including increased risk of disputes and litigation, as a result of the effects of the COVID-19 pandemic on market and economic conditions and actions government authorities and financial lenders take in response to those conditions. We may also face increased operational and reputational risks, including the potential for escalating counterparty risk. The COVID-19 pandemic has resulted, and may continue to result, in disruptions to some of our business partners, clients and customers and the way in which we conduct our business, including prolonged duration of staff working from home. These factors have impacted, and may continue to impact, our business operations and continuity of relationships with our business partners and lessees. Operational risks which may affect the Company or our business partners include the need to provide enhanced safety measures for employees and customers; complying with rapidly changing regulatory guidance; addressing the risks of attempted fraudulent activity and cybersecurity threat behavior; and protecting the integrity and functionality of the Company's systems, networks and data as a larger number of employees work remotely. To date, we have taken proactive measures through our business continuity plans to adapt to the ongoing work from home arrangements, carefully planning the return to the office environment for some of our employees, and our human resources team has increased its efforts to preserve the well-being of our employees and our ability to conduct business.

If the COVID-19 pandemic is further prolonged, including the possibility of additional subsequent waves, introduction of new variants or further diseases merge that give rise to similar effects, the adverse impact on the economy could deepen and result in further volatility and declines in commodity and financial markets. Moreover, it remains uncertain how the macroeconomic environment will be impacted following the COVID-19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Company's business and financial condition, potentially for a substantial period of time.

In virtually all aspects of our business and strategy, our view of risks is not static as our business activities expose us to a variety of risks. Consistent with our risk management framework, we actively manage our risks to help protect and enable our business and future prospects. Additionally, we continue to evaluate the impacts that the COVID-19 pandemic has had and continues to have on our business, including the impact on our top and emerging risks, operational and reputational risks as well as credit, market and liquidity and funding risks and environmental, social and governance risks. For further details on our risks, refer to the detailed risk factors below and throughout this AIF.

Volatility in the Petroleum and Natural Gas Industry

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the United States and Iran, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the COVID-19 pandemic), climate change concerns and political upheavals in various countries, including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. Through 2020, oil prices deteriorated due to softening global demand caused by the COVID-19 pandemic. In March

2020, OPEC and Russia were unable to reach an agreement to further manage oil production volumes to support global oil prices. Saudi Arabia responded by reducing its pricing and promising to increase production to over 10 million bbl/day. These actions led to the deepest drop in crude oil prices that global markets have seen since 1991. With the rapid spread of COVID-19 and additional oil supply, oil prices and global equity markets deteriorated significantly, and they remain under pressure. The extreme supply/demand imbalance caused a reduction in industry spending in 2020, which is expected to continue into 2021. The crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. It is anticipated that the oil and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum 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 petroleum and natural gas industry in Western Canada and cross-border with the United States 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 – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access*").

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 – Pricing and Marketing in Canada" and "Risk Factors –Volatility in the Petroleum 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 crude oil and natural gas business.

Crude 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. See "*Industry Conditions - Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access*" and "*Risk Factors - Volatility in the Petroleum and Natural Gas Industry*".

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 - Volatility in the Petroleum 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 adjusted funds 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.

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 and severe weather events and natural disasters, including fire, drought and flooding; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; political uncertainty; availability and productivity of skilled labour; environmental and Indigenous activism that potentially results in delays or cancellations of projects; 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.

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.

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 of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of adjusted funds 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.

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, commitments to carbon reduction 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 crude 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 negative effect on Tamarack's business, financial condition, results of operations and adjusted funds flows.

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 reserves 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. Where the Company engages in risk management activities related to foreign exchange rates, there is a potential credit risk associated with counterparties with which the Company may contract. .

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, which negative impact could prove to be material over time.

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 negative effect on future results of operations, liquidity and financial condition, which could prove to be material over time.

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. See "*Risk Factors – Insurance*".

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. 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, natural disasters and environmental conditions, 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.

In June 2021 TC Energy confirmed the termination of the Keystone XL Pipeline. It is unclear what the direct impact of the termination of this project will be on the Company.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. 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 CEAA 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 as few projects have been tested under this legislative scheme. Projects which are subject to an impact assessment under the IAA, and other revamped provincial legislation, will be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of a proposed project subject to the legislation, as well as the effects of projects on Indigenous peoples and their rights which may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation.

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.

Regulatory

Crude 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"*.

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. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities* and *Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

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, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licencee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continues to implement its AB LMF, with changes to be gradually phased in throughout 2022, replacing the current AB LMR Program. The implementation of the AB LMF Program 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, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, 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 SCC's decision in Redwater on the AER's rules and policies, lending practices in the petroleum 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 LMF may prevent or interfere with a third party's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude 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*".

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. There is no guarantee the current provincial regimes in place will continue to meet federal stringency requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

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.

Foreign and domestic governments continue to evaluate and implement policy, legislation and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. 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 operating expenses, and, in the long-term, potentially reducing the demand for crude oil and natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets. See "*Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks*", and "*Risk Factors – Reputational Risk*".

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. The application was denied and ENvironment JEUnesse appealed to the Appeal Court of Québec on February 23, 2021. The appeal was dismissed on December 13, 2021. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against crude 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 perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing and providing insurance coverage to crude oil and natural gas and related infrastructure businesses and projects. The impact of such efforts may require the Company's management to dedicate significant time and resources to these climate change related concerns, may adversely affect the Company's operations, the demand for and price of the Company's securities and may negatively impact the Company's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Claims have been made against certain energy companies alleging that GHG emissions from crude oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities or other organizations may make claims against crude oil and natural gas companies, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse effect on its financial condition, which could prove to be material.

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. Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires, and most recently with extreme flooding in British Columbia, causing temporary interruption to both inter-provincial pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the third-parties' ability to transport produced crude oil and natural gas as well as goods and services in their supply chains and meet demand due to temporary interruptions.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high 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.

Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. 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 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.

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 crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

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.

Credit Facility and Senior Notes 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 senior notes, 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 or senior notes 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 and senior notes 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 net debt to trailing annual adjusted funds flow to rise above its peer standards. The level of Tamarack's indebtedness or net debt to trailing annual adjusted funds flow 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;
- 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, GHG emissions reduction, 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, including the use of environmental metrics in executive compensation. 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, Sustainability 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.

Dividends

The amount of future cash dividends paid by the Company is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; tax laws; foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time and, as a result, future cash dividends could be reduced or suspended entirely. The Credit Facility may prohibit the Company from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price or liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in losses to shareholders.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditures using funds from operations.

To the extent that the Company is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Foreign Exchange Risk on Dividends

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Inflation and Cost Management

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Tamarack's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to Tamarack's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and funds from operations.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond 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, 2021, with a preparation date of January 18, 2022, 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 been 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.

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.

In addition, the Company competes with numerous other entities in the search for, and the acquisition of, petroleum and natural gas properties and in the marketing of petroleum and natural gas. In particular, the Company competes with other companies for the acquisition of royalty interests in petroleum and natural gas properties. Other companies may have access to substantially greater financial resources, staff, political influence or facilities than those of the Company and who may have lower costs of, and better access to, capital. The Company's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential.

Political Uncertainty

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact Tamarack's existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that the Company relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact Tamarack's results.

Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Company's products.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again 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. 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 petroleum and natural gas industry including the balance between economic development and environmental policy. 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, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates – Curtailment*", and "*Industry Conditions – The United States Mexico Canada 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.

The level of geo-political risk escalates at certain points in time. While the specific impact on the global economy would depend on the nature of the event, in general, any major event could result in instability and volatility. Current areas of concern include: global uncertainty and market repercussions due to the spread of COVID-19; Russia's military invasion of Ukraine; and rising civil unrest and activism globally.

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.

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.

Conflicts of Interest

Certain directors and officers of Tamarack are also, or may in the future be, directors or officers of other crude 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.

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, new development or new project approvals 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 negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. 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, environmental issues 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.

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.

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.

Social Media

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.

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 25, 2022, 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 March 30, 2021 relating to the annual meeting of shareholders held on May 12, 2021. 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, 2021.

DEFINITIONS

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

"**AB LMF**" means the Government of Alberta's Liability Management Framework;

"**AB LMR Program**" means the Alberta Liability Management Program, as replaced by the AB LMF;

"**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;

"**CEAA**" means the Canadian Environmental Assessment Act of 2012;

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

"**CERA**" 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;

"**CFS**" means the Federal Government's Clean Fuel Standard;

"**Clearwater Acquisitions**" means the two strategic acquisitions completed by the Company on December 21, 2020 in the Clearwater oil play, establishing a position in the Greater Nipisi area and interests in the Jarvie area of Alberta, for a total net purchase price of $74.0 million, after deducting the proceeds from the sale of a 2% newly created gross overriding royalty on a select portion of the acquired properties.

"**COGE Handbook**" means the most recent publication of 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;

"COVID-19" means the novel coronavirus which was declared a global pandemic by the World Health Organization on March 11, 2020;

"CO_2e" means carbon dioxide equivalent;

"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 $550 million and an extendible revolving working capital credit facility in the amount of $50 million; next annual review before June 30, 2022;

"**Crestwynd**" means Crestwynd Exploration Ltd., as acquired by the Corporation on February 15, 2022;

"**CUKTCA**" means the Canada-United Kingdom Trade Continuity Agreement;

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

"**Dunhaven**" means Dunhaven Energy Inc.;

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

"**ESG**" means environmental, social and governance;

"**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;

"**GGPPA**" means the Federal Government's Greenhouse Gas Pollution Pricing Act;

"**GHG**" means greenhouse gas;

"**GLJ**" means GLJ Ltd., independent qualified reserves evaluators;

"**GLJ Report**" means the independent engineering report dated January 25, 2022 and evaluating the crude oil, natural gas and NGL reserves of the Company effective as of December 31, 2021;

"**GORR Disposition**" means the sale of a 2% newly created gross overriding royalty on a select portion of the properties acquired in the Clearwater Acquisitions;

"**HEHE Plan**" means the Healthy Environment and a Healthy Economy Plan;

"**IA Agency**" means the Impact Assessment Agency of Canada;

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

"**IOGA**" means the Indian Oil and Gas Act;

"**IWCP**" means the Inactive Well Compliance Program, implemented by the AER;

"**LLR Program**" means Licensee Liability Rating Program;

"**LMR**" means liability management rating, a ratio of a licensee's assets to liabilities across the AB LMR Program;

"**MRGGA**" means the Management and Reduction of Greenhouse Gases Act, announced by Government of Saskatchewan in May 2009;

"**NAFTA**" means the North American Free Trade Agreement;

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

"**NEB**" means National Energy Board, which was replaced with the CER in summer of 2019;

"**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;

"**Preferred Shares**" means preferred shares in the capital of Tamarack Valley Energy Ltd.;

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

"**PUD**" means proved undeveloped reserves;

"**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;

"**SLB Framework**" means Tamarack's Sustainability-Linked Bond Framework;

"**SLL**" means sustainability-linked lending facility;

"**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.;

"**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;

"**TIER**" means Alberta's Technology Innovation and Emissions Reduction regulation;

"**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;

"**UNFCCC**" means the United Nations Framework Convention on Climate Change;

"**USMCA**" means the United States Mexico Canada Agreement; and

"**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	Barrels
Mbbl	thousand barrels
Mmbbl	million barrels
Mstb	1,000 stock tank barrels
Bbl/d	barrels per day
BOPD	barrels of oil per day
NGL	natural gas liquids
STB	stock tank barrels

Natural Gas

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

Other

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

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

SELECTED CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic meters	28.320
cubic meters	cubic feet	35.315
Bbl	cubic meters	0.159
cubic meters	Bbl	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, including the assets acquired under the Clearwater Acquisitions and the West Central acquisition;
- the COVID-19 pandemic, the Company's and governmental authorities' current and planned responses thereto and the impact thereof on, without limitation, the Company in particular and the oil and gas industry in general;
- environmental, health, safety and social policies and plans, including the Company's commitment to the practices outlined in the Company's 2021 Sustainability Report;
- 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, including increased operating and capital costs due to inflationary pressures;
- 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;
- future PSU 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 2022;
- expected source of funds in connection with the Company's capital program;
- expectations regarding commodity prices in 2022;
- deployment of the Company's 2022 capital program;
- future dividend payments;
- the expected allocation of the Company's 2022 capital expenditure budget;
- the source of funds for the Company's 2022 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 realization of anticipated benefits of acquisitions, including the Clearwater Acquisitions and the West Central acquisition and the related drilling programs;

- 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:

- global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19 and including the evolution of new variants of COVID-19 and delays relating to vaccine development, procurement and distribution;
- volatility in market prices for oil and natural gas, price differentials and the actual prices received for the Company's products;
- ability to pay dividends;
- 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;
- 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 Gross (Net)	Booked - Proved Gross (Net)	Booked - Probable Gross (Net)	Unbooked Gross (Net)
Clearwater	549 (470.5)	50 (49)	28 (26)	471 (395.5)
Charlie Lake	247 (246.4)	65 (64.5)	32 (31.9)	150 (150)
EOR(1)	93 (87)	42 (42)	11 (11)	40 (34)
Cardium and Other	655 (581.1)	191 (180.5)	105 (99.8)	359 (300.8)

Notes:
(1) EOR locations represent patterns. Patterns will vary by field but are most frequently represented by a producer-injector pair.

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.

SPECIFIED FINANCIAL MEASURES

This document contains various specified financial measures including non-IFRS financial measures, non-IFRS financial ratios and capital management measures as further described herein. The Company uses these measures to help evaluate its performance; however, these 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 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 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. The Company also considers capital cost payout a key measure as it demonstrates the financial status of the Company's projects.

(a) **Adjusted Funds Flow (Capital Management Measure)** - 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 cash-flow from operating activities and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment. Adjusted funds flow can also be calculated on a per boe basis. 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 15 of the Company's 2021 Management's Discussion and Analysis in the section titled "*Adjusted funds flow and Net Income (Loss)*".

(b) **Free Funds Flow (Capital Management Measure)** – (formerly referred to as free adjusted funds flow) Tamarack's method of calculating free funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Free funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

(c) **Operating Netback and Operating Field Netback (Non-IFRS Financial Measures)** - 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 (on a boe basis, this is a non-IFRS financial ratio). The calculation of the Company's netbacks can be seen on page 11 of the Company's 2021 Management's Discussion and Analysis in the section titled "*Operating Netback*".

(d) **Net Debt (Capital Management Measure)** - 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, including the fair value of cross-currency swaps, plus other liability and excluding the current portion of the fair value of financial instruments, decommissioning obligations and lease liabilities) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

(e) **Net Debt to Trailing Annual Adjusted Funds Flow (Capital Management Measure)** – Management uses certain industry benchmarks, such as year-end net debt to trailing annual 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 estimated net debt at a point in time divided by the estimated adjusted funds flow for the four preceding quarters. Management considers net debt to trailing annual 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 year's estimated results.

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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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 Ltd.	Dec 31/21	Canada	0	2,953,476	0	2,953,476

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.

6. 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.

7. 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 Ltd., Calgary, Alberta, Canada, January 25, 2022.

"Originally Signed by"

Patrick A. Olenick, 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) "*Martin Malek*"

Martin Malek, Vice President, Engineering

(signed) "*Ian Currie*"

Ian Currie, Director

(signed) "*John Leach*"

John Leach, Director

(signed) "*Robert Spitzer*"

Robert Spitzer, Director

January 25, 2022

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.