tamarack valley ENERGY ltd.

MANAGEMENT'S REPORT

The accompanying audited consolidated financial statements and all information in this report are the responsibility of management. Management, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, has prepared the accompanying audited consolidated financial statements of Tamarack Valley Energy Ltd. (the "Company"). The audited consolidated financial statements have been prepared within acceptable limits of materiality and when necessary, management has made estimates using their best judgment.

Management is responsible for the integrity of the financial information. Management has established internal control systems designed to provide reasonable assurance that transactions are properly authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable accounting information for financial reporting purposes.

The Company's Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Company's Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with Management and their external auditors to discuss internal controls over financial reporting process, audit results and financial reporting matters to satisfy itself that each party is discharging its responsibilities, and to review the consolidated financial statements and the external auditors' report. The external auditors have access to the Audit Committee on a quarterly basis without the presence of management. The Board of Directors has approved the audited consolidated financial statements.

(signed)
Brian Schmidt
President & Chief Executive Officer

(signed)
Steve Buytels
VP Finance & Chief Financial Officer

Calgary, Alberta
February 26, 2021

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tamarack Valley Energy Ltd.

Opinion

We have audited the consolidated financial statements of Tamarack Valley Energy Ltd. (the "Company"), which comprise:

- the consolidated balance sheets as at December 31, 2020 and December 31, 2019
- the consolidated statements of loss and comprehensive loss for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2020 and December 31, 2019, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2020. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of indicators of impairment or impairment reversal for the cash-generating units

Description of the matter

We draw attention to note 2, note 3 and note 8 to the financial statements. The Company assesses at each reporting date whether there is an indication that each of the Company's cash-generating units ("CGUs") may be impaired or that historical impairment may be reversed. The Company determined that there were no external or internal indicators of impairment or historical impairment reversal at December 31, 2020 for the Viking oil, Cardium oil, minor gas and Clearwater oil CGUs and no impairment tests were required. Significant management judgments are required to analyze the relevant external and internal indicators of impairment or impairment reversal with the estimate of proved and probable oil and natural gas reserves and the related cash flows being significant to the Company's assessment.

The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted production and transportation costs
- Forecasted royalty costs
- Forecasted future development costs.

The Company engages an external independent qualified reserves evaluator to estimate the proved and probable oil and natural gas reserves and the related cash flows as at December 31, 2020.

Why the matter is a key audit matter

We identified the assessment of indicators of impairment or impairment reversal for the CGUs as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures with respect to external and internal indicators of impairment or impairment reversal included in the Company's indicator assessment, including the estimate of proved and probable oil and natural gas reserves and the related cash flows.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

- We evaluated the Company's assessment of external and internal indicators of impairment or impairment reversal by considering whether the quantitative and qualitative information in the analysis was consistent with external market and industry data, the Company's press releases and certain minutes of the Board of Directors and the estimate of proved and probable oil and natural gas reserves and the related cash flows.

- With respect to the estimate of proved and probable oil and natural gas reserves and the related cash flows as at December 31, 2020:
  - We evaluated the competence, capabilities and objectivity of the external independent qualified reserves evaluator engaged by the Company
  - We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
  - We compared the 2020 actual production, production and transportation costs, royalty costs and future development costs of the Company to those estimates used in the prior year's estimate of proved oil and natural gas reserves and the related cash flows to assess the Company's ability to accurately forecast
  - We evaluated the appropriateness of forecasted production and forecasted production and transportation costs, royalty costs and future development costs assumptions by comparing to 2020 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

Assessment of the recoverable amount of the Viking oil, Cardium oil, Penny oil and minor gas cash-generating units

Description of the matter

We draw attention to note 2, note 3 and note 8 to the financial statements. The Company has recorded an aggregate impairment charge of $399.0 million related the Viking oil, Cardium oil, Penny oil and minor gas CGUs for the year ended December 31, 2020. The Company identified an indicator of impairment at March 31, 2020 in each of these CGUs and identified an indicator of impairment in the Penny oil CGU at December 31, 2020 and performed an impairment test to estimate the recoverable amount of each of these CGUs.

The estimated recoverable amount of each CGU involves significant estimates, including:

- The estimate of proved and probable oil and natural gas reserves and the related cash flows
- The discount rates.

The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted production and transportation costs
- Forecasted royalty costs
- Forecasted future development costs.

The Company engages an external independent qualified reserves evaluator to estimate the proved and probable oil and natural gas reserves and the related cash flows at December 31 of each year. For purposes of the March 31, 2020 impairment tests, the Company's internal reserves evaluator updated the significant assumptions from the external independent qualified reserves evaluator's estimate of proved and probable oil and natural gas reserves and the related cash flows as at December 31, 2019.

Why the matter is a key audit matter

We identified the assessment of the recoverable amount of the Viking oil, Cardium oil, Penny oil and minor gas CGUs as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and natural gas reserves and the related cash flows and the discount rates.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

- With respect to the estimate of proved and probable oil and natural gas reserves and the related cash flows at December 31, 2019 and December 31, 2020:
  - We evaluated the competence, capabilities and objectivity of the external independent qualified reserves evaluator engaged by the Company
  - We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
  - We compared the 2019 and 2020 actual production, production and transportation costs, royalty costs and future development costs of the Company to those estimates used in the prior year's estimate of proved oil and natural gas reserves and the related cash flows to assess the Company's ability to accurately forecast
  - We evaluated the appropriateness of forecasted production and forecasted production and transportation costs, royalty costs and future development costs assumptions by comparing to 2019 and 2020 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.
- With respect to the estimate of proved and probable oil and natural gas reserves and related cash flows as at March 31, 2020:
  - We evaluated the competence, capabilities and objectivity of the internal reserves evaluator
  - We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
  - We evaluated the appropriateness of forecasted production and forecasted production and transportation costs, royalty costs and future development costs assumptions by comparing to corresponding amounts in the proved and probable oil and natural gas reserves and the related cash flows estimated by the external independent qualified reserves evaluator as at December 31, 2019 and by comparing to 2019 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.
- We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Company's discount rates by comparing the discount rates to market and other external data
- Assessing the reasonableness of the Company's estimate of the recoverable amount of the CGUs by comparing the Company's estimate to market metrics and other external data.

Other Information

Management is responsible for the other information. Other information comprises the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters

in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 26, 2021

TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets
(thousands)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Accounts receivable (note 5)	**$30,781**	$42,219
Prepaid expenses and deposits	**1,265**	1,924
Fair value of financial instruments (note 5)	**981**	114
	33,027	44,257
Fair value of financial instruments (note 5)	**–**	275
Property, plant and equipment (note 7, 8 and 9)	**943,430**	1,200,950
Exploration and evaluation assets (note 10)	**1,460**	1,637
Deferred tax asset (note 15)	**49,683**	–
	$1,027,600	$1,247,119
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$38,903**	$37,809
Lease liabilities (note 13)	**2,484**	2,209
Decommissioning obligations (note 11)	**6,000**	–
Cross-currency swap (note 19)	**1,597**	2,908
Fair value of financial instruments (note 5)	**9,942**	4,475
	58,926	47,401
Bank debt (note 19)	**210,857**	192,907
Lease liabilities (note 13)	**7,670**	9,961
Fair value of financial instruments (note 5)	**1,192**	–
Decommissioning obligations (note 11)	**239,437**	184,846
Deferred tax liability (note 15)	**–**	38,229
	518,082	473,344
Shareholders' equity:		
Share capital (note 17)	**876,124**	832,799
Treasury shares (note 17)	**(703)**	(969)
Contributed surplus	**51,347**	47,811
Deficit	**(417,250)**	(105,866)
	509,518	773,775
Subsequent event (note 5)		
Commitments (note 21)		
Contingency (note 22)		
	$1,027,600	$1,247,119

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

(signed) Floyd Price, Director

(signed) John Leach, Director

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Loss and Comprehensive Loss
For the years ended December 31, 2020 and 2019
(thousands, except per share amounts)

	2020	2019
Revenue:		
Oil and natural gas (note 6)	**$220,896**	$381,066
Processing income (note 6)	**1,177**	1,750
Royalties	**(24,540)**	(39,060)
Net revenue	**197,533**	343,756
Financial instrument contracts:		
Realized gain (loss) on financial instruments (note 5)	**32,936**	(12,516)
Unrealized loss on financial instruments (note 5)	**(6,067)**	(23,746)
Net revenue and gain (losses) on financial instruments	**224,402**	307,494
Expenses:		
Production and transportation	**86,515**	89,897
General and administration	**11,082**	12,464
Stock-based compensation (note 20)	**5,500**	9,689
Finance (note 16)	**12,635**	13,569
Depletion, depreciation and amortization (note 7 and 10)	**120,658**	167,311
Gain on disposition of property, plant and equipment (note 7)	**(10,665)**	(27)
Site rehabilitation program grant (note 11)	**(1,395)**	–
Impairment of property, plant and equipment (note 8)	**399,000**	68,000
	623,330	360,903
Loss before taxes	**(398,928)**	(53,409)
Deferred income tax recovery (note 15)	**87,544**	14,398
Net loss and comprehensive loss	**$(311,384)**	$(39,011)
Net loss per share (note 18):		
Basic	**$(1.40)**	$(0.17)
Diluted	**$(1.40)**	$(0.17)

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity
(thousands)

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2019	226,072	$848,249	$(3,377)	$34,554	$(66,855)	$812,571
Issue of common shares	15	41	–	–	–	41
Settlement of RSUs	163	595	–	(782)	–	(187)
Purchase of common shares for cancellation	(4,181)	(16,112)	–	7,852	–	(8,260)
Purchase of common shares for RSU exercise	(1,641)	–	(3,452)	–	–	(3,452)
RSU exercise	2,365	–	5,860	(5,860)	–	–
Transfer on exercise of stock options	–	26	–	(26)	–	–
Stock-based compensation	–	–	–	12,073	–	12,073
Net loss	–	–	–	–	(39,011)	(39,011)
Balance at December 31, 2019	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Balance at January 1, 2020	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Issue of common shares	40,925	47,064	–	–	–	47,064
Purchase of common shares for cancellation	(664)	(2,551)	–	1,262	–	(1,289)
Purchase of common shares for RSU exercise	(3,641)	–	(3,857)	–	–	(3,857)
RSU exercise	3,363	–	4,123	(4,123)	–	–
Share issue costs, net of tax of $368	–	(1,188)	–	–	–	(1,188)
Stock-based compensation	–	–	–	6,397	–	6,397
Net loss	–	–	–	–	(311,384)	(311,384)
Balance at December 31, 2020	262,776	$876,124	$(703)	$51,347	$(417,250)	$509,518

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2020 and 2019
(thousands)

	2020	2019
Cash provided by (used in):		
Operating:		
Net loss	**$(311,384)**	$(39,011)
Depletion, depreciation and amortization (note 7 and 10)	**120,658**	167,311
Stock-based compensation (note 20)	**5,500**	9,689
Gain on disposition of property, plant and equipment (note 7)	**(10,665)**	(27)
Site rehabilitation program grant (note 11)	**(1,395)**	–
Accretion expense on decommissioning obligations (note 11)	**2,573**	4,075
Unrealized loss on financial instruments (note 5)	**6,067**	23,746
Unrealized loss (gain) on foreign exchange	**1,249**	(2,859)
Unrealized loss (gain) on cross-currency swap (note 19)	**(1,311)**	2,908
Impairment of property, plant and equipment (note 8)	**399,000**	68,000
Deferred income tax recovery (note 15)	**(87,544)**	(14,398)
Abandonment expenditures (note 11)	**(3,825)**	(3,154)
Changes in non-cash working capital (note 14)	**6,367**	(11,049)
Cash provided by operating activities	**125,290**	205,231
Financing:		
Change in bank debt (note 19)	**16,701**	34,271
Net proceeds from issuance of shares (note 17)	**45,508**	41
Purchase of common shares for cancellation (note 17)	**(1,289)**	(8,260)
Purchase of common shares for RSU exercises (note 17)	**(3,857)**	(3,639)
Purchase of leased asset (note 13)	**–**	(22,328)
Repayment of lease liabilities (note 13)	**(2,348)**	(2,738)
Changes in non-cash working capital (note 14)	**1,556**	–
Cash provided by (used in) financing activities	**56,271**	(2,653)
Investing:		
Property, plant and equipment additions (note 7)	**(102,975)**	(179,088)
Exploration and evaluation additions (note 10)	**(568)**	122
Acquisitions (note 9)	**(98,811)**	(9,942)
Proceeds from disposal of property, plant and equipment (note 7)	**15,525**	–
Changes in non-cash working capital (note 14)	**5,268**	(13,670)
Cash used in investing activities	**(181,561)**	(202,578)
Change in cash and cash equivalents	**–**	–
Cash and cash equivalents, beginning of year	**–**	–
Cash and cash equivalents, end of year	**$ –**	$ –

See accompanying notes to the consolidated financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The consolidated financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 600, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8.

2. Basis of preparation:

(a) **Statement of compliance:**

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements were authorized for issue by the Board of Directors on February 26, 2021.

(b) **Basis of measurement:**

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments (including cross-currency swaps) which are measured at fair value.

(c) **Functional and presentation currency:**

These consolidated financial statements are presented in Canadian dollars, which is the Company's and its subsidiaries functional currency, other than Tamarack Ridge Resources Inc. that has a United States dollar functional currency.

(d) **COVID-19:**

Beginning in the first quarter of 2020, global oil prices declined considerably caused by reduced demand driven by the novel coronavirus ("COVID-19") health pandemic and over supply concerns stemming from failed negotiations between OPEC+ countries on production curtailments. While the OPEC+ countries have now reached an agreement on production cuts, the macro environment remains subject to increased volatility and considerable uncertainty exists regarding the duration and extent of oil demand destruction from the COVID-19 pandemic due to the emergence of new variant strains of the virus and the global availability of access to vaccines effective against the initial and variant strains of the virus. There has also been significant market volatility in energy shares and foreign exchange markets, and restrictions on the conduct of business in many jurisdictions. The current challenging economic climate may have significant impacts on the Company, including, but not limited to:

- significant changes in revenue and cash flows due to increased volatility in oil and natural gas commodity pricing,

- changes in future revenue could result in impairment charges and, or reversals of historical impairment charges to long-term assets,
- increased risk of non-performance by the Company's customers which could materially increase collection risk of accounts receivable and customer defaults on contracts, and
- prolonged demand destruction could negatively impact the Company's ability to maintain liquidity.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect to the Company is not known at this time. Estimates and judgments made by management in the preparation of these consolidated financial statements are subject to a higher degree of measurement uncertainty during this volatile period. As an understanding of the longer-term impacts of COVID-19 on commodity, credit and equity markets develops, there is amplified potential for changes in these estimates and judgments.

(e) **Use of estimates and judgments:**

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

i) Critical judgments in applying accounting policies

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

The Company's assets are aggregated into cash-generating units for the purpose of calculating impairment. Cash-generating units ("CGU" or "CGUs") are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment pertaining to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

Significant management judgments are required to analyze the relevant external and internal indicators of impairment or impairment reversal for a CGU with the estimate of proved and probable oil and natural gas reserves and the related cash flows being significant to the assessment.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of proved and/or probable oil and natural gas reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

The application of the Company's accounting policy for business combinations requires management to make certain judgments on a case-by-case basis as to the determination of the accounting method of an acquisition to determine if the assets acquired meet the definition of a business requiring the acquisition method of accounting for a business combination or an asset acquisition when applying the optional asset concentration test.

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

ii) Key sources of estimation uncertainty

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

The amounts recorded for depletion of property, plant and equipment, the provision of decommissioning obligations, business combinations and asset acquisitions, the realization of future taxable earnings for deferred income tax asset recognition, the determination of technical feasibility and commercial viability of exploration and evaluation assets, indicators of impairment or impairment reversal and amounts used in an impairment calculation are based on estimates of proved and probable oil and natural gas reserves and the related cash flows. By their nature, these estimates of proved and probable oil and natural gas reserves and the related cash flows are subject to uncertainty including significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs and forecasted future development costs. Tamarack's estimated proved and probable oil and natural gas reserves and the related cash flows have been prepared at December 31 of each year by the Company's external independent qualified reserves evaluator, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101.

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

The Company's estimate of stock-based compensation is dependent upon estimates of expected volatility and forfeiture rates as well as performance multipliers estimated by management on the Company's performance share units.

The Company's estimate of the fair value of derivative financial instruments and cross-currency swaps is dependent on estimated variables including forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently by the Company and its subsidiaries to all years presented in these consolidated financial statements, except as provided for in (m) below.

(a) Basis of consolidation:

i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) *Business combinations:*

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets acquired and liabilities and contingent liabilities assumed is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit or loss. Business combination associated transaction costs are expensed when incurred. The cost of an acquisition that does not meet the definition of a business under IFRS and does not qualify as a business combination is measured as the fair value of the consideration given and liabilities incurred or assumed at the date of exchange. No goodwill arises on an asset acquisition and the cost of the assets acquired and liabilities assumed are allocated to the assets and liabilities on the basis of their relative fair values at the date of purchase. Asset acquisition associated transaction costs are capitalized as a cost of the acquisition.

iii) *Jointly owned assets:*

Many of the Company's oil and natural gas activities involve jointly owned assets. The consolidated financial statements include the Company's share of these jointly owned assets and a proportionate share of the relevant revenue and related costs. The relationship with jointly owned asset partners has been referred to as joint venture in the remainder of the consolidated financial statements as is common in the Canadian oil and gas industry.

iv) *Transactions eliminated on consolidation:*

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments:

i) *Financial instruments:*

The Company recognizes financial assets and financial liabilities, including derivatives, on the balance sheet when the Company becomes a party to the contract. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or when the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized from the consolidated financial statements when the liability is extinguished either through settlement of, or release from, the obligation of the underlying liability.

Financial assets, financial liabilities and derivatives are measured at fair value on initial recognition. Measurement in subsequent periods depends on the financial instrument's classification, as described below.

• Amortized cost - A financial asset is measured at amortized cost if the objective of the business model is to hold the financial asset for the collection of the cash flows; and all contractual cash flows represent only principal and interest on that principal. All financial liabilities are measured at amortized cost using the effective interest method except for liabilities incurred for the purposes of selling or repurchasing in the short-term, if they are held-for trading and those that meet the definition of a derivative.

• Fair value through other comprehensive income ("FVOCI") - A financial asset shall be measured at FVOCI if the financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and the contractual terms of the financial asset give rise on specified dates to cash flows that are Solely Payment of Principal and Interest ("SPPI") on the principal amount outstanding.

• Fair value through profit or loss ("FVTPL") - All financial assets that do not meet the definition of being measured at amortized cost or FVOCI are measured at FVTPL, this includes all derivative financial assets. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. For financial assets and liabilities, the Company may make an irrevocable election to designate an asset at FVTPL. If the election is made it is irrevocable, meaning that asset, liability, or group of financial instruments must be recorded at FVTPL until that asset, liability or group of financial instruments are derecognized.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Commodity contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a commodity in accordance with the Company's expected purchase, sale or usage fall within the normal purchase or sale exemption and are accounted for as executory contracts. Financial assets are assessed with an expected credit loss model. The expected credit loss model applies to financial assets measured at amortized cost, a lease receivable, a contract asset or a loan commitment and a financial guarantee contract.

Accounts receivable, accounts payable and accrued liabilities and bank debt are measured at amortized cost while financial derivative contracts (including cross-currency swaps) are measured at FVTPL. The Company has not designated any financial instruments as FVOCI, nor does the Company use hedge accounting.

ii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects. When the Company repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. The excess of the purchase price over the carrying value is recognized as a deduction from retained earnings or conversely credited to contributed surplus when the carrying value exceeds the purchase price. Shares are cancelled upon repurchase.

(c) **Property, plant and equipment and exploration and evaluation ("E&E") assets:**

i) Recognition and measurement:

E&E expenditures:

Pre–license costs are recognized in profit or loss as incurred.

E&E costs, including the costs of acquiring licenses, initially are capitalized as E&E assets. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are evaluated at a CGU level.

A review of each exploration license or field is carried out, at least annually, to ascertain whether technical feasibility and commercial viability have been established.

Upon determination that technical feasibility and commercial viability of E&E assets has been established, E&E assets attributable to those proved and probable oil and natural gas reserves are first tested for impairment and then reclassified from E&E assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal or the fair value of the asset received or given up with the carrying amount of the related property, plant and equipment given up and are recognized net in profit or loss.

ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable oil and natural gas reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day–to–day servicing of property, plant and equipment are recognized in profit or loss as incurred.

iii) Depletion, depreciation and amortization:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable oil and natural gas reserves, taking into account estimated future development costs necessary to bring those reserves into production. Production and reserves of natural gas are converted to equivalent barrels of oil based on the energy equivalent ratio of six thousand cubic feet of natural gas to one barrel of oil. Future development costs are estimated by taking into account the level of development required to produce the reserves. These estimates are reviewed by independent qualified reserves evaluators at least annually.

E&E assets pertaining to undeveloped land are amortized on a straight-line basis over the term of the lease.

For other assets, depreciation is recognized in profit or loss on a percentage basis based on the useful life of the assets.

The estimated depreciation rates for other assets for the current and comparative years are as follows:

Computer hardware and software	30 %
Office equipment, fixtures and fittings	20 %

Depreciation methods, useful lives and salvage values are reviewed at each reporting date.

(d) Leased assets and liabilities:

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether:

- the contract involves the use of an identified asset; this may be specified explicitly or implicitly and should be physically distinct or represent substantially all of the capacity of a physically distinct asset. If the supplier has a substantive substitution right, then the asset is not identified;

- the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- the Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used. In rare cases where the decision is predetermined, the Company has the right to direct the use of the asset if either:
    1. the Company has the right to operate the asset; or
    2. the Company designed the asset in a way that predetermines how and for what purpose it will be used.

When the Company is a lessee, it recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated from the commencement date to the earlier of the end of useful life of the right-of-use assets or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. In addition, the right-of-use asset is reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

Lease payments included in the measurement of the lease liability comprise the following:

- fixed payments, including in-substance fixed payments;
- variable lease payments that depend on an index or rate, initially measured at the index or rate as at the commencement date; and
- amounts expected to be payable under a residual value guarantee; and the exercise price under a purchase option that the Company is reasonably certain to exercise, lease payments in an option renewal period if the Company is reasonably certain to exercise an extension option, and penalties for early termination of a lease unless the Company is certain not to terminate early.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option.

When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amounts of the right-of-use asset has been reduced to nil.

The Company presents right-of-use assets in "property, plant and equipment" and lease obligations in "lease liabilities" in the consolidated balance sheet.

(e) **Impairment:**

i) Financial assets:

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

ii) Non-financial assets:

The carrying amounts of the Company's non–financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any external or internal indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated. E&E assets, which are evaluated with the related CGU when they are assessed for impairment, are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Right-of-use assets may be tested as part of a CGU, as a separate CGU or as an individual asset.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal.

Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction. In determining fair value less costs of disposal, discounted cash flows and recent market transactions are taken into account. These calculations are corroborated by valuation multiples or other available fair value indicators.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre–tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable oil and natural gas reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the other assets in the unit or group of units on a pro rata basis.

Any impairment losses in respect of property, plant and equipment and E&E assets, recognized in prior years, are assessed at each reporting date for any indications that the losses have decreased or no longer exist. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(f) **Share based payments:**

The grant date fair value of preferred shares, stock options, restricted share units and performance share units granted to employees is recognized as compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of awards that vest.

(g) **Provisions:**

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre–tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

ii) Onerous contracts:

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on associated assets.

(h) **Revenue:**

Revenues from the sale of oil, natural gas and NGL are measured based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured. This is generally considered to occur when legal title to the product passes to customers, which is when it is physically transferred to the pipeline or other transportation method agreed upon. The nature of each of its performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal, and therefore recognizes revenue on a gross basis, or as an agent, and therefore recognizes revenue on a net basis. The Company acts as the principal when it controls the product delivered before the control passes to its customer. Revenues from processing activities are recognized over time as processing occurs, and generally billed monthly.

(i) **Finance income and expenses:**

Finance expense is comprised of interest expense on bank debt, interest expense on lease liabilities, unrealized foreign exchange translation gains or losses, unrealized gains or losses on cross-currency swaps, accretion of the discount on decommissioning obligations and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company’s outstanding borrowings during the period.

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the rate of exchange prevailing at the reporting date, while non-monetary assets and liabilities that are measured in terms of historical cost are translated using the exchange rates at the dates of the transactions. Foreign currency gains and losses are reported on a net basis as either finance income or finance expense depending on whether foreign currency movements are in a net gain or net loss position.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(j) **Income tax:**

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in profit or loss, except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) **Flow–through shares:**

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow–through share arrangements are renounced to investors in accordance with tax legislation. On issuance, the premium received on the flow–through shares, being the difference in price over a common share with no tax attributes, is recognized on the balance sheet. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized in profit or loss along with a pro–rata portion of the deferred premium.

(l) **Earnings per share:**

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of common shares is adjusted for shares purchased and held by the Company (treasury shares). Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as preferred shares, stock options, restricted share units and performance share units granted to employees.

(m) **Changes in accounting policies:**

IFRS 3 "Business Combinations"

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 "Business Combinations". The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant's perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process.

The amendments to IFRS 3 are effective for annual reporting periods beginning on January 1, 2020 and apply prospectively to these financial statements. Refer to note 9, "Property acquisitions".

IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance"

The Company applied IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance" in relation to receiving the Canada Emergency Wage Subsidy ("CEWS") as part of the federal government of Canada's response to the COVID-19 health pandemic, as well as the Alberta Site Restoration Program ("SRP") and the Saskatchewan Accelerated Site Closure Program ("ASCP"). Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. Grants that compensate the Company for expenses incurred are recognized as a reduction to the related expense on a systematic basis in the periods in which the expenses are recognized. When the conditions of a grant relate to an underlying obligation, it is recognized as a reduction to the obligation and recognized in profit or loss when the conditions of the grant have been met and the receipt of the grant is reasonably assured. The Company has recorded $1.3 million of CEWS payments received as a reduction to general and administrative expense for the year ended December 31, 2020. The Company has recorded $1.4 million of SRP and ASCP support payments received as a reduction to decommissioning obligations and recorded other income from the site rehabilitation program grant on the consolidated statement of loss and comprehensive loss for the year ended December 31, 2020.

4. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods outlined below. The Company's fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(a) Property, plant and equipment and E&E assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the estimates of proved and probable oil and natural gas reserves and the related cash flows as prepared by the Company's external independent qualified reserves evaluator. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of other items of property, plant and equipment and E&E assets is based on the quoted market prices for similar items.

(b) Accounts receivable, bank debt and accounts payable and accrued liabilities:

The fair value of accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2020 and 2019, the fair value of these balances approximated their carrying value due to their short term to maturity.

Bank debt bears a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value.

(c) **Stock options, preferred shares, restricted share units and performance share units:**

The fair value of employee stock options and preferred shares is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on weighted average historic volatility, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividend yield and the weighted average risk-free interest rate based on government bonds. Restricted share units and performance share units are valued at the share price on the measurement date.

(d) **Derivatives:**

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted amounts and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. Derivatives are recorded on the balance sheet at fair value with the change in fair value being recognized as an unrealized gain or loss in profit or loss. Cross-currency swaps are recorded on the balance sheet at fair value with the change in fair value being recognized as a finance expense.

5. Financial risk management:

(a) **Overview:**

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Company's activities.

(b) **Credit risk:**

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers and favorable mark-to-market positions on financial instruments. The maximum exposure to credit risk at year-end is as follows:

($ thousands)	Carrying amount	
As at December 31,	**2020**	2019
Accounts receivable	**$30,781**	$42,219
Fair value of financial instruments	**981**	389
Total	**$31,762**	$42,608

Accounts receivable:

All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from oil and natural gas purchasers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas purchasers.

Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining joint venture partner pre-approval of significant capital expenditures.

However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners; as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners; however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment.

Derivative assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company manages the credit risk exposure related to derivative assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. The lifetime expected credit losses allowances related to the Company's oil and natural gas marketers and joint venture receivables were nominal as at and for the years ended December 31, 2020 and 2019.

The maximum exposure to credit risk for accounts receivable at the reporting date by type of customer was:

($ thousands) As at December 31,	Carrying amount 2020	2019
Oil and natural gas marketing companies	**$23,922**	$33,708
Joint venture partners	**4,451**	3,542
Other	**2,408**	4,969
Total accounts receivable	**$30,781**	$42,219

The Company's six most significant customers, four Canadian oil and natural gas marketers, and two joint venture partners, account for $19.3 million of the account receivables at December 31, 2020 (December 31, 2019: four Canadian oil and natural gas marketers, and two joint venture partners accounted for $29.5 million).

As at December 31, 2020 and 2019, the Company's accounts receivable is aged as follows:

($ thousands)	2020	2019
Current (less than 90 days)	**$28,344**	$40,503
Past due (more than 90 days)	**2,437**	1,716
Total accounts receivable	**$30,781**	$42,219

(c) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically, the Company ensures that it has sufficient cash or available credit facility available to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

The timing of cash flows relating to financial liabilities as at December 31, 2020 is as follows:

($ thousands)	Total	Less than 1 Year	1 to 3 years	Beyond 3 years
Account payable and accrued liabilities	$38,903	$38,903	$–	$–
Fair value of financial instruments	11,134	9,942	1,192	–
Cross currency swap	1,597	1,597	–	–
Bank debt	210,857	–	210,857	–
Total financial liabilities	$262,491	$50,442	$212,049	$–

Refer to note 13 for a maturity analysis of the Company's lease liabilities.

(d) **Market risk:**

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors quarterly.

Currency risk:

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally a decrease in the value of the $CDN as compared to the $US will increase the prices received by the Company for its petroleum and natural gas sales. The Company holds hedges to mitigate foreign exchange risk as detailed in the table below in addition to cross-currency swaps to remove the foreign exchange risk of LIBOR based borrowings (see notes 16 and 19).

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank debt fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has entered into mitigating interest rate swaps to cover a portion of this exposure. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2020, net loss would have been affected by $1,557 (December 31, 2019 – $1,379) based on the average debt balance outstanding during the year.

Commodity price risk:

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

(thousands, except per share and per unit amounts)

At December 31, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	**Volume (bbls/d)**	**2,000**	**1,750**	**–**	**–**
	Average Price (US$/bbl)	$41.33	$45.67	–	–
WTI fixed price swap (with swaption)[1]	**Volume (bbls/d)**	**2,500**	**2,000**	**500**	**–**
	Average Price (US$/bbl)	$45.25	$47.20	$50.00	–
WTI two-way collar (with swaption)[2]	**Volume (bbls/d)**	**1,500**	**1,500**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	$40.00	–	–
	Average Sold Call (US$/bbl)	$51.17	$51.17	–	–
WTI two-way collar	**Volume (bbls/d)**	**500**	**750**	**1,000**	**1,000**
	Average Bought Put (US$/bbl)	$40.00	$41.67	$40.00	$40.00
	Average Sold Call (US$/bbl)	$50.00	$51.43	$50.50	$50.50
	Average Premium (US$/bbl)	$2.00	$1.67	$2.00	$2.00
WTI three-way collar	**Volume (bbls/d)**	**–**	**–**	**1,000**	**1,000**
	Average Bought Put (US$/bbl)	–	–	$40.00	$40.00
	Average Sold Call (US$/bbl)	–	–	$60.00	$60.00
	Average Sold Put (US$/bbl)	–	–	$32.00	$32.00
	Average Premium (US$/bbl)	–	–	$2.00	$2.00
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	**Volume (bbls/d)**	**4,250**	**4,250**	**3,250**	**3,250**
	Average Price (US$/bbl)	($5.70)	($5.70)	($5.68)	($5.68)
WCS to WTI fixed price differential swap	**Volume (bbls/d)**	**1,000**	**500**	**–**	**–**
	Average Price (US$/bbl)	($11.75)	($12.00)	–	–

(1) If fully exercised would result in additional fixed price hedges of: 1,500 bbls/day at $46.00 (Q2/21); 2,000 bbls/day at $47.22 (Q3/21); and 1,500 bbls/day at $46.00 (Q4/21).

(2) If fully exercised would result in additional fixed price hedges of 1,500 bbls/day at $51.17 (H2/21).

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	**Amount ($US/month)**	**$1,000,000**	**$1,000,000**	–	–
	Average Forward Rate (CAD/USD)	1.4140	1.4140	–	–
CAD/USD average rate forward (with extension option)[1]	**Amount ($US/month)**	**$500,000**	**$500,000**	–	–
	Average Forward Rate (CAD/USD)	1.3843	1.3843	–	–
CAD/USD collar style swap (with extension option)[2]	**Amount ($US/month)**	**$500,000**	**$500,000**	**$500,000**	**$500,000**
	Floor Forward Rate (CAD/USD)	1.3000	1.3000	1.3000	1.3000
	Ceiling Forward Rate (CAD/USD)	1.3615	1.3615	1.3615	1.3615

(1) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3843 (H2/21).

(2) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3615 (2022).

(thousands, except per share and per unit amounts)

		2021	2022	2023	2024
Interest Rate Derivatives					
CDOR Interest Rate Fixed Price Swap	**Amount (MM CAD/year)**	**$80.0**	**$80.0**	**$49.1**	**$6.4**
	Fixed Interest Rate	1.533%	1.533%	1.225%	1.043%

At December 31, 2020, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability of $10,153 (December 31, 2019 - $4,086 net liability) recorded on the balance sheet. The Company had an unrealized loss of $6,067 recorded in earnings for the year ended December 31, 2020 (December 31, 2019 - $23,746 unrealized loss).

Subject Contract	Effect of an increase in oil price, exchange rate or interest rate on after-tax earnings	Effect of a decrease in oil price, exchange rate or interest rate on after-tax earnings
Cdn $1.00 change in the oil price	($1,374)	$1,339
Cdn $0.01 change in the exchange rate	$69	($69)
0.25% change in the interest rate	($499)	$499

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue.

At December 31, 2020, the Company held the following physical commodity contracts:

		Winter 20-21	Summer 21	Winter 21-22
Natural Gas Derivatives				
AECO 5A	**Volume (GJ/d)**	**7,500**	**20,000**	**15,000**
	Average Price (CAD/GJ)	$2.42	$2.43	$2.80
Chicago	**Volume (DTH/d)**	**2,000**	–	–
	Average Price (US$/DTH)	$3.01	–	–
MichCon	**Volume (DTH/d)**	**2,000**	–	–
	Average Price (US$/DTH)	$2.85	–	–
Dawn	**Volume (DTH/d)**	**2,000**	–	–
	Average Price (US$/DTH)	$3.01	–	–
Malin	**Volume (DTH/d)**	**4,000**	**4,000**	–
	Average Price (US$/DTH)	$2.99	$2.83	–
WADD	**Volume (DTH/d)**	**5,000**	–	–
	Average Price (US$/DTH)	$3.90	–	–

Risk management contracts assets and liabilities are offset, and the net amount presented in the balance sheet, when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

The following table sets out gross amounts relating to risk management contracts assets and liabilities that have been presented on a net basis on the balance sheet.

Gross Amounts ($ thousands)	December 31, 2020	December 31, 2019
Risk management contracts		
Current asset	**$981**	$114
Long-term asset	–	275
Current liability	**(9,942)**	(4,475)
Long-term liability	**(1,192)**	–
Balance, end of the year	**$(10,153)**	$(4,086)

Since December 31, 2020, the Company has entered into the following derivative contracts:

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	***Volume (bbls/d)***	**–**	**500**	**250**	**–**
	Average Price (US$/bbl)	–	$49.60	$50.00	–
WTI two-way collar	***Volume (bbls/d)***	–	–	–	**500**
	Average Bought Put (US$/bbl)	–	–	–	$50.00
	Average Sold Call (US$/bbl)	–	–	–	$60.00
	Average Premium (US$/bbl)	–	–	–	$0.00
Crude Oil Differential Derivatives					
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**–**	**–**	**1,500**	**–**
	Average Price (US$/bbl)	–	–	($11.88)	–

Since December 31, 2020, the Company has not entered into any physical contracts.

(e) Capital management:

The Company's policy is to maintain a strong capital base to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized adjusted funds flow. This ratio is calculated as net debt, defined as outstanding bank debt plus accounts payable and accrued liabilities and cross-currency swap liabilities minus accounts receivable and prepaid expenses and deposits divided by adjusted funds flow for the most recent calendar quarter and then annualized. Tamarack calculates adjusted funds flow as cash provided by operating activities before the changes in non-cash working capital related to operating activities and abandonment expenditures. The Company's strategy during a period of stable commodity prices is to maintain a ratio of not more than 1.5 times, excluding the effect of acquisitions. This ratio may increase or decrease at certain times as a result of acquisitions, timing of employing capital versus bringing wells on production or significant upward/downward fluctuations in commodity prices.

The Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2020, the Company's ratio of net debt to annualized fourth quarter adjusted funds flow was 1.9 to 1 (December 31, 2019 – 0.9 to 1).

($ thousands)	**December 31, 2020**	December 31, 2019
Working capital deficiency (surplus)	**$8,454**	$(3,426)
Bank debt	**210,857**	192,907
Net debt	**219,311**	189,481
Quarterly adjusted funds flow	**$28,894**	$54,742
Annualized factor	**4**	4
Annualized adjusted funds flow	**115,576**	218,968
Net debt to annualized adjusted funds flow	**1.9x**	0.9x

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the Company's estimated proved and probable oil and natural gas reserves.

6. Revenue:

The Company sells its production pursuant to fixed-price or variable-price contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of light oil, heavy oil, natural gas or NGL to the contract counterparty.

Revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Tamarack's efforts to transfer production and therefore the resulting revenue is allocated to the production volumes delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. The Company's contracts with customers generally have a term of one year or less, except in the case of certain natural gas contracts, whereby delivery takes place throughout the contract period. Revenues are normally collected on the business day nearest the 25th day of the month following sale.

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; and the Barons Sand oil play in the Penny area of southern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at December 31, 2020, four customers accounted for $17.6 million of the accounts receivable (December 31, 2019, four customers accounted for $28.7 million).

The following table presents the Company's total revenues disaggregated by revenue source:

Years ended December 31, ($ thousands)	2020	2019
Light oil	**$169,261**	$316,819
Heavy oil	**2,857**	8,876
Natural gas	**34,011**	40,231
Natural gas liquids	**14,767**	15,140
Oil and natural gas revenue	**$220,896**	$381,066
Processing income	**1,177**	1,750
Total revenue	**$222,073**	$382,816

Refer to note 5 for a listing of physical delivery contracts as at December 31, 2020.

Included in accounts receivable at December 31, 2020 was $24.2 million (December 31, 2019 - $34.7 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at December 31, 2020, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

7. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2019	$1,858,155	$1,585	$1,859,740
Right-of-use assets (note 13)	37,236	–	37,236
Property acquisitions	10,598	–	10,598
Cash additions	178,678	410	179,088
Decommissioning costs	(8,719)	–	(8,719)
Stock-based compensation	2,384	–	2,384
Transfer from exploration and evaluation assets (note 10)	30	–	30
Disposals	(2,035)	–	(2,035)
Balance at December 31, 2019	2,076,327	1,995	2,078,322
Right-of-use assets (note 13)	–	332	332
Property acquisitions (note 9)	111,339	–	111,339
Cash additions	102,691	284	102,975
Decommissioning costs	45,850	–	45,850
Stock-based compensation	897	–	897
Transfer from exploration and evaluation assets (note 10)	148	–	148
Balance at December 31, 2020	$2,337,252	$2,611	$2,339,863
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2019	$643,187	$920	$644,107
Depletion and depreciation	166,049	263	166,312
Disposals	(1,047)	–	(1,047)
Impairment (note 8)	68,000	–	68,000
Balance at December 31, 2019	876,189	1,183	877,372
Depletion and depreciation	119,667	394	120,061
Impairment (note 8)	399,000	–	399,000
Balance at December 31, 2020	$1,394,856	$1,577	$1,396,433

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2019	$1,200,138	$812	$1,200,950
At December 31, 2020	$942,396	$1,034	$943,430

(a) **Security:**

At December 31, 2020 and 2019, all of the Company's properties were pledged as security for the bank debt (note 19).

(b) **Contingencies:**

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

(c) **Dispositions:**

For the year ended December 31, 2020 the Company disposed of a 2% gross overriding royalty ("GORR") on a select portion of the Clearwater properties acquired (see note 9) for proceeds of $15.5 million and recorded a gain on disposition of $10.7 million. For the year ended December 31, 2019 the Company disposed of its interest in one non-core property for interest in undeveloped land and recorded a gain of $27.

(d) **Other:**

The calculation of depletion at December 31, 2020 includes estimated future development costs of $637,332 (December 31, 2019 – $700,604) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of $79,357 (December 31, 2019 – $70,791).

Certain facilities, surface and office leases are included in property, plant and equipment as right-of-use assets:

($ thousands)	Processing facilities	Surface leases	Office leases	Total
As at January 1, 2019	$35,326	$1,910	$ –	$37,236
Exercise of purchase option	(22,568)	–	–	(22,568)
Depletion and depreciation	(2,529)	(174)	–	(2,703)
Impairment	(827)	–	–	(827)
As at January 1, 2020	$9,402	$1,736	$ –	$11,138
Lease additions	–	–	332	332
Depletion and depreciation	(1,366)	(150)	(145)	(1,661)
Impairment	(3,123)	(308)	–	(3,431)
Balance at December 31, 2020	$4,913	$1,278	$187	$6,378

8. Impairment:

(a) **2020 assessment:**

The Company determined that there were no external or internal indicators of impairment or historical impairment reversal at December 31, 2020 for the Viking oil, Cardium oil, minor gas and Clearwater oil CGUs and no impairment tests were required. However, there were indicators of impairment for the Penny oil CGU.

At December 31, 2020, an impairment charge of $18,000 was recorded as a result of a decrease in the current quantities of recoverable proved and probable oil and natural gas reserves at the

(thousands, except per share and per unit amounts)

Company's Penny oil CGU. The estimated recoverable amount of this CGU as at December 31, 2020, net of decommissioning obligations, was estimated to be $62.0 million based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amount of the Penny oil CGU was determined using the fair value less costs of disposal methodology based on what Tamarack could receive for the assets in this CGU if it disposed of them in the current environment taking into account lower oil and natural gas commodity prices.

The results of Tamarack's impairment tests are sensitive to changes in forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs, forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs and result in impairment charges or in the reversal of historical impairment charges.

As at December 31, 2020, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately $3.2 million to the Penny oil CGU, a $1.00/bbl Cdn change to oil prices would result in a change to impairment of approximately $2.5 million to the Penny oil CGU.

The following forecasted oil and natural gas commodity price assumptions were used in determining whether an impairment or reversal of impairment to the carrying value of the CGUs existed at December 31, 2020, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2021	2022	2023	2024	2025	2026	2027	2028	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7683	0.7650	0.7633	0.7633	0.7633	0.7633	0.7633	0.7633	0.7633
WTI (US$/bbl)(1)	47.17	50.17	53.17	54.97	56.07	57.19	58.34	59.50	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	55.76	59.89	63.48	65.76	67.13	68.53	69.95	71.40	+2.0%/yr
AECO (Cdn$/mmbtu)(1)	2.78	2.70	2.61	2.65	2.70	2.76	2.81	2.86	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective January 1, 2021.

At March 31, 2020 an impairment charge of $381,000 was recorded as a result of a decrease in current and forecasted oil and natural gas commodity prices. The impairment recognized relates to the Company's CGUs as follows: the Viking oil CGU was impaired $235,000 , the Cardium oil CGU was impaired $137,000, the Penny oil CGU was impaired $7,000 and the minor gas CGU was impaired $2,000. The estimated recoverable amount of these CGUs as at March 31, 2020, net of decommissioning obligations, was $447.9 million for the Viking oil CGU, $137.9 million for the Cardium oil CGU, $81.4 million for the Penny oil CGU and ($11.1) million for the minor gas CGU based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2019 and updated by the Company's internal reserves evaluator to March 31, 2020 for production, production and transportation costs, royalty costs, future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the fair value less costs of disposal methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account lower oil and natural gas commodity prices. The impairment charge of $381,000 was allocated to property, plant and equipment in the amount of $377,569 and $3,431 was allocated to the right-of-use asset.

The results of Tamarack's impairment tests are sensitive to changes in forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs, forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs and result in impairment charges or in the reversal of historical impairment charges.

As at March 31, 2020, all else being equal, a 1% change in the discount rate, a $1.00/bbl Cdn change to oil prices and a $0.10/mmbtu Cdn change to natural gas prices would result in the following changes to the impairment charge recognized:

Impairment expense ($ millions)	1% change in discount rate	$1.00 Cdn change in oil price	$0.10/mmbtu Cdn change in gas price
Viking oil CGU	$15.9	$17.1	$2.9
Cardium oil CGU	7.9	5.9	5.5
Penny oil CGU	4.1	3.1	0.3
Minor gas CGU	0.3	0.4	0.4
Total	$28.2	$26.5	$9.1

The following forecasted oil and natural gas commodity price assumptions were used in determining whether an impairment or reversal of impairment to the carrying value of the CGUs existed at March 31, 2020, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2020	2021	2022	2023	2024	2025	2026	2027	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7067	0.7283	0.7450	0.7467	0.7483	0.7500	0.7500	0.7500	0.7500
WTI (US$/bbl)(1)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	+2.0%/yr
AECO (Cdn$/mmbtu)(1)	1.74	2.20	2.37	2.45	2.52	2.60	2.66	2.72	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective April 1, 2020.

(thousands, except per share and per unit amounts)

The Company has recorded an aggregate impairment charge of $399,000 related to the Viking oil, Cardium oil, Penny oil and minor gas CGUs for the year ended December 31, 2020.

(b) **2019 assessment:**

An impairment charge of $68,000 was recorded as at December 31, 2019 as a result of a decrease in current and forecasted natural gas prices. The impairment recognized relates to the Company's Cardium CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The estimated recoverable amount of this CGU as at December 31, 2019, net of decommissioning obligations, was $273.7 million based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amount of the Cardium CGU was determined using the fair value less costs of disposal methodology based on what Tamarack could receive for the assets in this CGU if it disposed of them in the current environment taking into account lower current and forecasted natural gas prices. The impairment of $68,000 was allocated to property, plant and equipment in the amount $67,173 and $827 was allocated to the right-of-use asset.

The results of Tamarack's impairment tests are sensitive to changes in forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs, forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs and result in impairment charges or in the reversal of historical impairment charges.

As at December 31, 2019, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately $14.5 million to the Cardium oil CGU, a $1.00/bbl Cdn change to forecasted oil prices would result in a change to impairment of approximately $5.8 million to the Cardium oil CGU, and a $0.10/mmbtu Cdn change to forecasted natural gas prices would result in a change to impairment of approximately $7.0 million to the Cardium oil CGU.

The following forecasted oil and natural as commodity price assumptions were used in determining whether an impairment or reversal of impairment to the carrying value of the CGUs existed at December 31, 2019, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2020	2021	2022	2023	2024	2025	2026	2027	Thereafter
Exchange rate (US$/Cdn$)[(1)]	0.7600	0.7700	0.7850	0.7850	0.7850	0.7850	0.7850	0.7850	0.7850
WTI (US$/bbl)[(1)]	61.00	63.75	66.18	67.91	69.48	71.07	72.68	74.24	+2.0%/yr
Edmonton Par (Cdn$/bbl)[(1)]	72.64	76.06	78.35	80.71	82.64	84.60	86.57	88.49	+2.0%/yr
AECO (Cdn$/mmbtu)[(1)]	2.04	2.32	2.62	2.71	2.81	2.89	2.96	3.03	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective January 1, 2020.

9. Property acquisitions:

On December 21, 2020, the Company completed two concurrent acquisitions of certain oil and gas properties located in the Greater Nipisi area of Alberta from two separate unrelated parties. The combined assets were acquired for total cash consideration of $94.9 million, including $2.4 million of capitalized transaction costs.

The first acquisition was completed for total cash consideration of $53.9 million, including $1.1 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction will be included in a newly formed Clearwater oil CGU.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	51,389
Assets held for sale (note 7)		2,759
Decommissioning obligations		(274)
Net assets acquired	**$**	**53,874**
Purchase consideration:		
Cash	$	53,874
Total purchase consideration	**$**	**53,874**

The second acquisition was completed for total cash consideration of $41.0 million including $1.3 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction will be included in a newly formed Clearwater oil CGU.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	39,219
Assets held for sale (note 7)		2,101
Decommissioning obligations		(282)
Net assets acquired	**$**	**41,038**
Purchase consideration:		
Cash	$	41,038
Total purchase consideration	**$**	**41,038**

On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets were acquired for total cash consideration of $4.0 million including $0.1 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)		**Amount**
Net assets acquired:		
Oil and natural gas interests	$	20,845
Decommissioning obligations		(16,832)
Net assets acquired	**$**	**4,013**
Purchase consideration:		
Cash	$	4,013
Total purchase consideration	**$**	**4,013**

10. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2019	$26,006
Additions	(122)
Transfer to property, plant and equipment (note 7)	(30)
Balance at December 31, 2019	25,854
Additions	568
Transfer to property, plant and equipment (note 7)	(148)
Balance at December 31, 2020	$26,274
Accumulated amortization and impairment:	
Balance at January 1, 2019	$23,218
Amortization	999
Balance at December 31, 2019	24,217
Amortization	597
Balance at December 31, 2020	$24,814

	Total
Carrying amounts:	
At December 31, 2019	$1,637
At December 31, 2020	$1,460

11. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $233.9 million at December 31, 2020 (December 31, 2019 – $195.6 million), which is expected to be incurred between 2021 and 2045. A risk-free rate of 1.2% (December 31, 2019 – 1.8%) and an inflation rate of 1.5% (December 31, 2019 – 1.4%) is used to calculate the present value of the decommissioning obligations at December 31, 2020 as presented in the table below:

($ thousands)	**December 31, 2020**	December 31, 2019
Balance, beginning of the year	**$184,846**	$193,003
Liabilities incurred	**3,839**	12,031
Liabilities acquired (note 9)	**17,388**	–
Change in estimates	**20,051**	(20,750)
Change in discount rate on acquisition	**21,960**	–
Expenditures	**(3,825)**	(3,154)
Site rehabilitation program grant	**(1,395)**	–
Liabilities disposed	**–**	(359)
Accretion	**2,573**	4,075
Balance, end of the year	**$245,437**	$184,846

Revisions due to the change of discount rate on acquisition of $22.0 million results from the difference between the fair value discount rate on the acquisition date and the subsequent revaluation using the risk-free rate.

During the year ended December 31, 2020, approximately $1.4 million was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work.

Timing of decommissioning obligation expenditures expected to be incurred are:

($ thousands)	As at December 31, 2020
Decommissioning obligations – Less than 1 year	$6,000
Decommissioning obligations – Greater than 1 year	239,437
Total	$245,437

12. Personnel expenses:

The aggregate payroll expense of employees and executive management was as follows:

Years ended December 31, ($ thousands)	2020	2019
Wages and salaries	**$8,495**	$9,104
Government emergency wage subsidy	**(1,321)**	–
Benefits and other personnel costs	**1,748**	1,592
Stock-based compensation	**5,818**	11,384
Total employee remuneration	**14,740**	22,080
Capitalized portion of total remuneration	**(4,847)**	(6,226)
	$9,893	$15,854

Personnel expenses directly attributed to capital activities have been capitalized and included in property, plant and equipment.

In addition to their salaries, the Company also provides cash and non-cash benefits to executive officers and employees. The executive officers include the President and Chief Executive Officer, the VP Finance and Chief Financial Officer, the VP Engineering, the VP Land, the VP Exploration, VP Business Development and Corporate Planning and the VP Production and Operations. Executive officers, employees and directors may also participate in the Company's stock option and performance and restricted share unit program. Key executive officers' and directors' compensation is comprised of the following:

Years ended December 31, ($ thousands)	2020	2019
Salaries, wages and short-term benefits	**$4,218**	$4,674
Stock-based compensation (1)	**4,239**	7,056
	$8,457	$11,730

(1) Represents the amortization of stock-based compensation associated with restricted share units, performance share units and stock options granted to executive officers and directors as recorded in the financial statements.

13. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities, surface leases and the Company's head office lease. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the year ended December 31, 2020 were between 4.5% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at December 31, 2020:

Years ended December 31, ($ thousands)	**2020**	2019
Balance, beginning of the year	**$12,170**	$37,236
Lease additions	**332**	–
Interest expense	**840**	1,241
Lease payments	**(3,188)**	(3,979)
Exercise of purchase option	**–**	(22,328)
Balance, end of the year	**$10,154**	$12,170
Current portion	**$2,484**	$2,209
Long term portion	**$7,670**	$9,961

Undiscounted cash outflows relating to the lease liabilities are:

Years ended December 31, ($ thousands)	**2020**	2019
Less than 1 year	**$3,155**	$3,043
Years 2 and 3	**6,140**	6,076
Years 4 and 5	**3,110**	4,582
Thereafter	**2,309**	3,855
Total	**$14,714**	$17,556

The expense recognized relating to short-term leases and leases of low-value assets for the year ended December 31, 2020 was $0.1 million (December 31, 2019 - $0.1 million) and have been included in production and transportation expenses.

14. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Years ended December 31, ($ thousands)	2020	2019
Source/(use) of cash:		
Accounts receivable	**$11,438**	$(21,008)
Prepaid expenses and deposits	**659**	446
Accounts payable and accrued liabilities	**1,094**	(4,157)
	$13,191	$(24,719)
Related to operating activities	**$6,367**	$(11,049)
Related to financing activities	**$1,556**	$ –
Related to investing activities	**$5,268**	$(13,670)

The following are included in cash provided by operating activities:

Years ended December 31, ($ thousands)	2020	2019
Interest paid in cash on bank debt	**$8,611**	$7,573
Bank renewal fees	**673**	631
Interest paid on lease liabilities	**840**	1,241

The table below reconciles the movements of financial liabilities to cash flows arising from financing activities:

($ thousands)	Lease liabilities	Bank debt
Balance at January 1, 2019:	$–	$161,495
Changes from financing cash flows:		
Payment of lease liabilities	(2,738)	–
Purchase of leased asset	(22,328)	–
Draw on bank debt	–	34,271
Other changes:		
IFRS 16 adoption	37,236	–
Interest expense	1,241	–
Interest paid	(1,241)	–
Unrealized gain on foreign exchange	–	(2,859)
Balance at December 31, 2019	$12,170	$192,907
Changes from financing cash flows:		
Payment of lease liabilities	**(2,348)**	–
Draw on bank debt	–	**16,701**
Other changes:		
Interest expense	**840**	–
Lease additions	**332**	–
Interest paid	**(840)**	–
Unrealized loss on foreign exchange	**–**	**1,249**
Balance at December 31, 2020	**$10,154**	**$210,857**

15. Income taxes:

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to loss before taxes as follows:

Years ended December 31, ($ thousands)	2020	2019
Loss before taxes	**$(398,928)**	$(53,409)
Expected tax rate	**24.00%**	26.53%
Expected income tax recovery	**(95,743)**	(14,169)
Change in unrecognized deferred tax assets	**4,148**	(177)
Stock-based compensation	**1,320**	2,570
Change in rates and other	**2,731**	(2,622)
Deferred income tax recovery	**$(87,544)**	$(14,398)

In 2020, the blended statutory tax rate was 24.00% (December 31, 2019 – 26.53%). Alberta's government tabled legislation on May 28, 2019 to decrease the general corporate rate to 11% (from 12%) on July 1, 2019, with further 1% rate reductions every year on January 1 until the general corporate tax rate is 8% on January 1, 2022. Effective July 1, 2020, the Government of Alberta accelerated the general corporate tax rate reduction to 8%.

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, ($ thousands)	2020	2019
Deferred tax liabilities:		
Property, plant and equipment	**$(66,163)**	$(126,622)
Deferred tax assets:		
Financial instruments and foreign exchange	**2,331**	992
Non-capital losses	**54,439**	39,797
Share issue costs	**287**	320
Lease liabilities	**2,336**	2,921
Decommissioning obligations	**56,453**	44,363
Total	**$49,683**	$(38,229)

In calculating the deferred income tax liability in 2020, the Company included $237.1 million (December 31, 2019 - $165.8 million) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2028 and 2040.

Deferred tax assets have not been recognized in respect of the following item:

Years ended December 31, ($ thousands)	2020	2019
Property, plant and equipment	**$37,459**	$18,615

A continuity of the net deferred tax asset (liability) is detailed in the following tables:

($ thousands)	Balance January 1, 2019	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2019
Property, plant and equipment	$(139,706)	$ –	$ –	$13,084	$ –	$(126,622)
Lease liabilities	–	–	–	2,921	–	2,921
Non-capital losses	37,795	–	–	2,002	–	39,797
Decommissioning obligations	52,112	–	–	(7,749)	–	44,363
Share issue costs	2,480	–	–	(2,160)	–	320
Financial instruments and foreign exchange	(5,308)	–	–	6,300	–	992
Total	$(52,627)	$ –	$ –	$14,398	$ –	$(38,229)

($ thousands)	Balance January 1, 2020	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2020
Property, plant and equipment	$(126,622)	$ –	$ –	$60,459	$ –	$(66,163)
Lease liabilities	2,921	–	–	(585)	–	2,336
Non-capital losses	39,797	–	–	14,642	–	54,439
Decommissioning obligations	44,363	–	–	12,090	–	56,453
Share issue costs	320	368	–	(401)	–	287
Financial instruments and foreign exchange	992	–	–	1,339	–	2,331
Total	$(38,229)	$ 368	$ –	$87,544	$ –	$(49,683)

16. Finance expenses:

Years ended December 31, ($ thousands)	**2020**	2019
Interest on bank debt	**$9,284**	$8,204
Interest expense on lease liabilities	**840**	1,241
Unrealized loss (gain) on foreign exchange	**1,249**	(2,859)
Unrealized loss (gain) on cross-currency swap	**(1,311)**	2,908
Accretion of decommissioning obligations	**2,573**	4,075
	$12,635	$13,569

The Company manages its credit facility using a combination of bankers' acceptance loans and US dollar denominated London Inter-bank Offered Rate ("LIBOR") loans. During the year ended December 31, 2020, concurrent with the drawdown of US dollar LIBOR loans, the Company entered into cross-currency swaps ("CCS") to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of interest and principal repayments. At December 31, 2020, the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS.

17. Shareholders' equity:

a) Share capital:

At December 31, 2020 and 2019 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value. At December 31, 2020, Tamarack had issued and outstanding 262,776,395 Common Shares (December 31, 2019 – 222,793,117). No preferred shares have been issued.

During the year ended December 31, 2020 the Company issued 40,925,000 shares at $1.15 per common share for total proceeds of $47.1 million. Share issue costs in the amount of $1.6 million were incurred in association with the private placement financing.

During the year ended December 31, 2019 the Company settled 231,000 restricted share units ("RSUs") by issuing 163,000 Common Shares and a payment of $0.2 million for withholding tax on behalf of the employee in exchange for the remaining balance of 68,000 RSUs.

b) Normal course issuer bid:

On April 4, 2019, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares between April 8, 2019 and April 7, 2020.

During the year ended December 31, 2020, the Company purchased and cancelled 0.7 million Common Shares at an average price of $1.94 per Common Share, for a total repurchase cost of $1.3 million. The Company has decided not to renew the NCIB at this time due to the COVID-19 pandemic.

During the year ended December 31, 2019, the Company purchased and cancelled 4.2 million Common Shares at an average price of $1.98 per Common Share, for a total repurchase cost of $8.3 million.

c) Treasury shares:

During the year ended December 31, 2020, the Company spent $3.9 million to purchase 3.6 million Common Shares to be used to settle restricted share units ("RSUs") on the date of exercise. As at December 31, 2020, 746,742 Common Shares remain classified as treasury shares to be used for future settlements.

During the year ended December 31, 2019, the Company spent $3.5 million to purchase 1.6 million Common Shares to be used to settle RSUs on the date of exercise. As at December 31, 2019, 469,120 Common Shares remain classified as treasury shares to be used for future settlements.

18. Net loss per share:

The following table summarizes the net loss and weighted average shares used in calculating net loss per share:

($ thousands, except per share amounts)	**2020**	2019
Net loss	**$(311,384)**	$(39,011)
Weighted average shares - basic	**222,781**	225,219
Weighted average shares - diluted	**222,781**	225,219
Net loss per share-basic	**$(1.40)**	$(0.17)
Net loss per share-diluted	**$(1.40)**	$(0.17)

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the year ended December 31, 2020, 11.5 million Common Shares issuable upon the exercise and/or settlement of stock options ("Options"), RSUs, performance share units ("PSUs") and TAC Preferred Shares (as defined below) were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss (December 31, 2019 – 12.3 million).

19. Bank debt:

The Company currently has available a revolving credit facility in the amount of $255 million and a $20 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility, totaling $275 million, will be subject to its next extension by June 30, 2021. If not extended on June 30, 2021, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on both a net debt-to-cash-flow ratio and the total amount drawn down as defined in the Facility. The interest rate will vary depending on the lending vehicle employed, total loan value drawn and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") will vary based on a BA pricing grid from a low of the banks' posted rates plus 3.00% to a high of the banks' posted rates plus 7.00%. Interest on London Inter-bank Offered Rate Based Loans ("LIBOR") will vary based on a LIBOR pricing grid from a low of the banks' posted rates plus 3.25% to a high of the banks' posted rates plus 7.25%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 2.00% to a high of the banks' prime rates plus 6.00% with a 0.25% premium for amounts drawn in US funds. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.75% on the undrawn portion of the Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates. As at December 31, 2020, the Facility was secured by a $1.0 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's estimated proved and probable oil and natural gas reserves and forecasted commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by June 30, 2021.

At December 31, 2020, the Company had utilized the Facility in the amount of $210.9 million (December 31, 2019 - $192.9 million). The interest rate applicable to the drawn amounts as of this date was 3.86%. As at December 31, 2020, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility (December 31, 2019 - $0.2 million). There are no financial covenants governing the Facility.

The Company manages its credit facility using a combination of prime rate loans, bankers' acceptance notes and US dollar denominated LIBOR loans. During the year ended December 31, 2020, concurrent with the drawdown of US dollar LIBOR loans, the Company entered into cross-currency swaps (“CCS”) to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of interest and principal repayments. At December 31, 2020, the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS maturing at various times across the month of January 2021 (December 31, 2019 – the Company had drawn US$141.0 million, fixed at notional amounts of $185.9 million through various CCS).

20. Share-based payments:

The following table summarizes stock-based compensation expense relating to stock options, RSU’s and PSU’S:

Years ended December 31, ($ thousands)	2020	2019
Non-cash stock- based compensation		
Stock options	**$285**	$614
RSU's	**3,525**	8,197
PSU's	**2,587**	3,262
Total non-cash stock-based compensation:	**$6,397**	$12,073
Total capitalized costs	**(897)**	(2,384)
Total expensed non-cash stock-based compensation	**$5,500**	$9,689

(a) Preferred share plan:

At December 31, 2020, there are 740,307 (December 31, 2019 – 1,021,974) preferred shares of Tamarack Acquisition Corp. (the “TAC Preferred Shares”) issued and outstanding. At December 31, 2020, the TAC Preferred Shares were fully vested and exchangeable into 711,834 (December 31, 2019 – 982,667) Common Shares at an exchange price of $3.12 per Common Share.

Under the terms of the Company’s preferred share plan, a cashless settlement alternative is available, whereby holders of TAC Preferred Shares can either (i) elect to receive Common Shares by delivering cash to the Company in the amount of the TAC Preferred Shares, or (ii) elect to receive a number of Common Shares equivalent to the market value of the TAC Preferred Shares in excess of the TAC Preferred Shares at the exchange price of $3.12 per Common Share. For the year ended December 31, 2020 no TAC Preferred Shares were exchanged and 281,667 TAC Preferred Shares were forfeited.

(b) Options:

Pursuant to the Company's stock option plan (the "Stock Option Plan") and the Company's performance and restricted share unit plan (the "PRSU Plan"), the Company may grant up to an aggregate of 18.4 million Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at December 31, 2020, there was an aggregate of 10.8 million Options, RSUs and PSUs issued and outstanding.

Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.6 million Options granted during the year ended December 31, 2020 (December 31, 2019 – 0.4 million).

The fair value of each Option granted during the years ended December 31, 2020 and 2019 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2020	2019
Risk free rate (%)	**0.71**	1.59
Expected volatility (%)	**51**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**0.49**	1.65

The number and weighted average exercise prices of the Options are as follows:

	Number of Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2019	2,945	$3.95
Granted	390	2.57
Exercised	(15)	2.75
Expired	(1,127)	5.32
Outstanding, December 31, 2019	2,193	$3.01
Granted	559	1.13
Forfeited/expired	(848)	2.88
Outstanding, December 31, 2020	**1,904**	**$2.51**

The range of exercise prices of the Options outstanding and exercisable at December 31, 2020 is as follows:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 0.64 – 2.50	559	$1.13	4.2	–	–
$ 2.51 – 2.81	524	$2.60	2.7	254	$2.62
$ 2.82 – 3.44	821	$3.40	1.0	821	$3.40
$ 0.64 – 3.44	**1,904**	**$2.51**	**2.4**	**1,075**	**$3.22**

(c) **RSUs:**

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.0 million RSUs granted during the year ended December 31, 2020 (December 31, 2019 – 2.5 million).

For the purpose of calculating stock-based compensation, the fair value of each RSU is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the RSU value in cash or in Common Shares of the Company.

The following table summarizes information about the RSUs:

	Number of RSUs (thousands)
Outstanding, January 1, 2019	7,407
Granted	2,533
Exercised	(2,596)
Forfeited	(357)
Outstanding, December 31, 2019	6,987
Granted	1,986
Exercised	(3,363)
Forfeited	(245)
Outstanding, December 31, 2020	**5,365**
Exercisable, December 31, 2020	**1,903**

(d) **PSUs:**

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant 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 an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 1.7 million PSUs granted during the year ended December 31, 2020 (December 31, 2019 – 1.2 million).

For the purpose of calculating stock-based compensation, the fair value of each award is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the PSU value in cash or in Common Shares of the Company.

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2019	983
Awarded	1,211
Forfeited	(37)
Outstanding, December 31, 2019	2,157
Awarded	1,657
Forfeited	(250)
Outstanding, December 31, 2020	**3,564**
Earned, December 31, 2020	**683**
Exercisable, December 31, 2020	**–**

21. Commitments:

The following table summarizes the Company's commitments as at December 31, 2020:

($ thousands)	2021	2022	2023	2024	2025+
Lease(1)	131	174	174	174	131
Take or pay commitments(2)	3,950	4,023	3,894	–	–
Gas transportation(3)	2,293	1,627	535	143	7
Capital commitments(4)	25,000	55,000	–	–	–
Total	31,374	60,824	4,603	317	138

(1) Relates to the variable operating costs of the Company's head office lease which are a non-lease component of lease liabilities. A new head office is effective from April 1, 2021 to September 30, 2025. At lease commencement the Company will recognize an estimated lease liability and related right-of-use asset of $1.7 million. For the year ended December 31, 2020, $0.5 million of operating costs have been included within general and administrative expenses (December 31, 2019 - $0.5 million).

(2) Pipeline commitments to deliver a minimum of 636 m^3/d of crude oil/condensate and 455 m3/d of crude oil subject to a take-or-pay provision of $9.00/$m^3$ and $9.70/$m^3$, respectively, escalating approximately 2% per annum. The terms start on January 1, 2019 and lasts for 60 months.

(3) Gas transportation costs on long term firm contracts which are in various locations at variable rates.

(4) Commitment of $80.0 million of capital to further develop the 2% GORR Clearwater lands prior to December 31, 2022.

22. Contingency:

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 these consolidated financial statements.

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)(4)

Jeff Boyce(1)(4)

John Leach(1)(2)

Ian Currie(2)(4)

Rob Spitzer(2)(3)

Marnie Smith(1)(3)

Brian Schmidt

(1) Member of the Audit Committee of the Board of Directors
(2) Member of the Reserves Committee of the Board of Directors
(3) Member of the Compensation & Governance Committee of the Board of Directors
(4) Member of the Environmental, Safety and Sustainability Committee of the Board of Directors

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Martin Malek
VP Corporate Planning & Business Development

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

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