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)
Ron Hozjan
Vice-President & Chief Financial Officer

Calgary, Alberta
February 27, 2019

KPMG LLP
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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, 2018 and December 31, 2017
- the consolidated statements of income (loss) and comprehensive income (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, 2018 and December 31, 2017, 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.

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 represents 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.

The engagement partner on the audit resulting in this auditors' report is John Waiand.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 26, 2019

TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets
(thousands)

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Accounts receivable (note 5)	$21,211	$38,673
Prepaid expenses and deposits	2,370	3,095
Fair value of financial instruments (note 5)	20,518	1,941
	44,099	43,709
Fair value of financial instruments (note 5)	1,533	–
Property, plant and equipment (note 7)	1,215,633	1,162,272
Exploration and evaluation assets (note 9)	2,788	1,828
	$1,264,053	$1,207,809
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$41,966	$51,059
Fair value of financial instruments (note 5)	2,391	7,936
	44,357	58,995
Bank debt (note 17)	161,495	163,889
Fair value of financial instruments (note 5)	–	1,482
Decommissioning obligations (note 10)	193,003	177,793
Deferred tax liability (note 14)	52,627	31,795
Shareholders' equity:		
Share capital (note 15)	848,249	850,357
Treasury shares (note 15)	(3,377)	–
Contributed surplus	34,554	27,180
Deficit	(66,855)	(103,682)
	812,571	773,855
Commitments (note 19)		
Subsequent event (note 5)		
	$1,264,053	$1,207,809

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 Income (Loss) and Comprehensive Income (Loss)
For the years ended December 31, 2018 and 2017
(thousands, except per share amounts)

	2018	2017
Revenue:		
Oil and natural gas (note 6)	$398,804	$283,672
Processing income (note 6)	658	1,069
Royalties	(39,901)	(29,134)
Realized gain (loss) on financial instruments (note 5)	(17,945)	5,639
Unrealized gain on financial instruments (note 5)	27,137	3,495
	368,753	264,741
Expenses:		
Production	93,683	83,308
General and administration	13,386	12,462
Transaction costs	–	5,663
Stock-based compensation (note 18)	8,873	4,360
Finance (note 12)	12,178	10,834
Depletion, depreciation and amortization (notes 7 and 9)	177,576	148,649
Gain on disposition of property, plant and equipment (note 7)	(1,085)	–
Impairment of property, plant and equipment (note 8)	5,000	17,000
Total expenses	309,611	282,276
Income (loss) before taxes	59,142	(17,535)
Deferred income tax recovery (expense) (note 14)	(20,832)	3,611
Net income (loss) and comprehensive income (loss)	$38,310	$(13,924)
Net income (loss) per share (note 16):		
Basic	$ 0.17	$(0.06)
Diluted	$ 0.16	$(0.06)

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, 2017	137,527	$537,554	$ –	$21,942	$(89,758)	$469,738
Issue of common shares	90,983	311,698	–	–	–	311,698
Share issue costs, net of tax of $5.5	–	(14)	–	–	–	(14)
Transfer on exercise of stock options and RSUs	–	1,119	–	(1,119)	–	–
Stock-based compensation	–	–	–	6,357	–	6,357
Net loss	–	–	–	–	(13,924)	(13,924)
Balance at December 31, 2017	228,510	$850,357	–	$27,180	$(103,682)	$773,855
Issue of common shares	1,780	5,439	–	–	–	5,439
Purchase of common shares for cancellation	(3,025)	(11,593)	–	1,371	(1,483)	(11,705)
Purchase of common shares for RSU exercise	(1,804)		(5,799)	–	–	(5,799)
RSU exercise	611	–	2,422	(2,422)	–	–
Transfer on exercise of stock options and RSUs	–	4,046	–	(4,046)	–	–
Stock-based compensation	–	–	–	12,471	–	12,471
Net income	–	–	–	–	38,310	38,310
Balance at December 31, 2018	226,072	$848,249	$(3,377)	$34,554	$(66,855)	$812,571

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2018 and 2017
(thousands)

	2018	2017
Cash provided by (used in):		
Operating:		
Net income (loss)	$38,310	$(13,924)
Depletion, depreciation and amortization (notes 7 and 9)	177,576	148,649
Stock-based compensation (note 18)	8,873	4,360
Gain on disposition of property, plant and equipment (note 7)	(1,085)	–
Accretion expense on decommissioning obligations (note 10)	4,106	3,741
Unrealized gain on financial instruments (note 5)	(27,137)	(3,495)
Impairment of property, plant and equipment (note 8)	5,000	17,000
Deferred income tax expense (recovery) (note 14)	20,832	(3,611)
Abandonment expenditures (note 10)	(1,901)	(898)
Changes in non-cash working capital (note 13)	12,098	(7,297)
Cash provided by operating activities	236,672	144,525
Financing:		
Change in bank debt	(2,394)	118,662
Proceeds from issuance of shares (note 15)	5,439	1,606
Purchase of common shares for cancellation (note 15)	(11,705)	–
Purchase of common shares for RSU exercise (note 15)	(5,799)	–
Share issue costs	–	(19)
Cash provided by (used in) financing activities	(14,459)	120,249
Investing:		
Property, plant and equipment additions (note 7)	(223,319)	(183,210)
Exploration and evaluation additions (note 9)	(2,932)	(9,092)
Acquisitions (note 7)	(2,847)	(116,439)
Proceeds from disposal of property, plant and equipment (note 7)	9,889	5,301
Changes in non-cash working capital (note 13)	(3,004)	38,666
Cash used in investing activities	(222,213)	(264,774)
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 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9. 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, 2019.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments 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) 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.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

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 reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

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.

Estimation of recoverable quantities of proven and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows and the amount and timing of further development capital as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third party professional engineers, 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.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

The Company's estimate of stock-based compensation is dependent upon estimates of historic volatility and forfeiture rates.

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

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.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. 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, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in profit or loss.

ii) *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 financial statements as is common in the Canadian oil and gas industry.

iii) *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 consolidated statements of financial position 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 liabilities, 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 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.

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 assets:

i) *Recognition and measurement:*

Exploration and evaluation expenditures:

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

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

Exploration and evaluation 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, exploration and evaluation assets are evaluated at a CGU level.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered.

Upon determination of proven and/or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation 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 CGU's 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 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 proven and probable 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 reserve engineers at least annually.

Exploration and evaluation assets pertaining to 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. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

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 residual values are reviewed at each reporting date.

(d) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company's balance sheet. Payments made under operating leases are recognized in profit or loss on a straight–line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(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 exploration and evaluation ("E&E") assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets, which are evaluated with the related cash-generating unit 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.

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 proven and probable 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 exploration and evaluation 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 and restricted 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 crude oil, natural gas and natural gas liquids 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 comprises interest expense on bank debt, 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.

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

(j) Income tax:

Income tax expense comprises 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 and restricted share units granted to employees.

(m) Changes in accounting policies:

IFRS 15:

IFRS 15 “Revenue from Contracts with Customers” (“IFRS 15”) was issued by the IASB in May of 2014 and replaces IAS 18 “Revenue”, IAS 11 “Construction Contracts”, and related interpretations effective for reporting periods beginning on or after January 1, 2018. The new standard provides a single, principles-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized.

The Company has adopted IFRS 15 effective January 1, 2018. Tamarack applied IFRS 15 to all of its contracts with customers using the cumulative effect method. Under this method, prior period financial statements have not been restated. Management reviewed the Company’s revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when revenue is recognized. As a result, no adjustments were required in the January 1, 2018 opening balance sheet. The adoption of IFRS 15 does result in new disclosure requirements contained in note 6 of these consolidated financial statements.

Tamarack earns revenue from the following major sources:

- Sales from the production of light oil, heavy oil, natural gas and natural gas liquids; and
- Fees charged to third parties for processing and other services (i.e., gas and other product processing, etc.) provided at facilities where Tamarack has an ownership interest.

Revenues from the sale of crude oil, natural gas liquids and natural gas is recognized based on the consideration specified in contracts with customers. Tamarack recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. Revenues from processing activities are recognized over time as processing occurs and are generally billed monthly.

(thousands, except per share and per unit amounts)

The Company evaluates its arrangements with third parties and partners to determine if Tamarack is acting as the principal or as an agent. Tamarack is considered the principal in a transaction when it has primary responsibility for the transaction. If Tamarack acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

IFRS 9:

On January 1, 2018, the Company adopted all of the requirements of IFRS 9 “Financial Instruments” (“IFRS 9”) which replaces IAS 39 “Financial Instruments: Recognition and Measurement” (“IAS 39”). The retrospective adoption of IFRS 9 had no material impact to the Company’s consolidated financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company’s financial assets and financial liabilities:

	Measurement category	
Financial instrument	**IAS 39**	**IFRS 9**
Accounts receivable	Loans and receivables	Amortized cost
Financial derivative contracts	Fair value through profit or loss	Fair value through profit or loss
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
Bank debt	Financial liabilities at amortized cost	Amortized cost

There were no adjustments to the carrying amounts of the Company’s financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company does not apply hedge accounting.

IFRS 9 replaces the “incurred loss” model in IAS 39 with an “expected credit loss” (“ECL”) model. 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. The application of the new expected credit loss model did not have a significant impact on the Company’s financial assets.

(n) Future standards and interpretations:

Leases - In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in profit or loss when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expenses upon implementation. Cash flows associated with lease repayments will be allocated between operating and financing activities based on their interest repayment and principal repayment portions. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for the Company on January 1, 2019. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements and is in the final stage of gathering and analyzing contracts that will fall into scope of this standard. The Company expects adjustments for surface land rights, certain leased vehicles and field equipment, however, the full extent of the impact has not yet been finalized as the Company has not completed reviewing all of the contracts that it has in place.

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 exploration and evaluation 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 discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. 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 exploration and evaluation 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, 2018 and 2017, 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 and restricted 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 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.

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,	**2018**	2017
Accounts receivable	**$21,211**	$38,673
Fair value of financial instruments	**22,051**	1,941
Total	**$43,262**	$40,614

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 and foreign exchange 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 ECL 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, 2018 and 2017.

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 **2018**	 2017
Oil and natural gas marketing companies	**$14,173**	$33,753
Joint venture partners	**4,555**	2,968
Other	**2,483**	1,952
Total accounts receivable	**$21,211**	$38,673

The Company's nine most significant customers, eight Canadian oil and natural gas marketers, and one joint venture partner, account for $12.7 million of the accounts receivables at December 31, 2018 (December 31, 2017: six Canadian oil and natural gas marketers, and one joint venture partner accounted for $34.2 million). The Company has the ability to offset approximately 90% of the remaining amounts against current accounts payable from the same joint venture partners.

As at December 31, 2018 and 2017, the Company's accounts receivable is aged as follows:

($ thousands)	**2018**	2017
Current (less than 90 days)	**$20,189**	$37,726
Past due (more than 90 days)	**1,022**	947
Total accounts receivable	**$21,211**	$38,673

(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 banking line 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. In addition, the Company maintains a $290,000 credit facility to provide capital when needed, of which $128,331 was available at the end of 2018.

The timing of cash flows relating to financial liabilities as at December 31, 2018 is as follows:

($ thousands)	Total	1 Year	2 to 3 years	Beyond 3 years
Account payable and accrued liabilities	$41,966	$41,966	$–	$–
Fair value of financial instruments	2,391	2,391	–	–
Bank debt	161,495	–	161,495	–
Total financial liabilities	$205,852	$44,357	$161,495	$–

(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.

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 loan fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2018, net income would have been affected by $1,160 (December 31, 2017 net loss – $1,101) 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.

At December 31, 2018, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	400 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $63.10	$842
Crude oil	700 bbls/day	April 1, 2019 – June 30, 2019	WTI fixed price	US $65.45	$1,580
Crude oil	700 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $66.96	$1,533
Crude oil	4,140 bbls/day	January 1, 2019 – March 31, 2019	WTI put option	US $60.00	$7,162
Crude oil	3,220 bbls/day	April 1, 2019 – June 30, 2019	WTI put option	US $60.00	$5,570
Crude oil	3,105 bbls/day	July 1, 2019 – September 30, 2019	WTI put option	US $60.00	$5,371
Crude oil	2,990 bbls/day	October 1, 2019 – December 31, 2019	WTI put option	US $60.00	$5,173
Crude oil	4,000 bbls/day	January 1, 2019 – December 31, 2019	Edm par diff	US $12.13	($3,798)
Foreign exchange	6,750,000 US$/mth	January 1, 2019 – March 31, 2019	Exchange rate	Cdn $1.3074	($1,125)
Foreign exchange	6,750,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.3046	($1,126)
Foreign exchange	5,750,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3065	($887)
Foreign exchange	4,750,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.3111	($635)
					$19,660

At December 31, 2018, the commodity and foreign exchange contracts were fair valued with an asset value of $19,660 (December 31, 2017 - $7,477 liability) recorded on the balance sheet and an unrealized gain of $27,137 recorded in earnings for the year ended December 31, 2018 (December 31, 2017 - $3,495 unrealized gain).

Subject Contract	Effect of an increase in price on after-tax earnings	Effect of a decrease in price on after-tax earnings
Cdn $1.00 change in the oil price	$(2,080)	$2,080
Cdn $0.01 change in the exchange rate	$(526)	$526

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, 2018, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	25,000 mmbtu/day	January 1, 2019 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.77
Natural gas	10,000 mmbtu/day	April 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	5,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.51

Risk management contract 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, 2018**	December 31, 2017
Risk management contracts		
Current asset	**$20,518**	$1,941
Long-term asset	**1,533**	–
Current liability	**(2,391)**	(7,936)
Long-term liability	**–**	(1,482)
Balance, end of the year	**$19,660**	$(7,477)

Since December 31, 2018, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,000 bbls/day	April 1, 2019 – June 30, 2019	Edm par diff	US $5.95

Since December 31, 2018, 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 operating field netback. This ratio is calculated as net debt, defined as outstanding bank debt plus accounts payable and accrued liabilities minus accounts receivable and prepaid expenses and deposits divided by adjusted operating field netback for the most recent calendar quarter and then annualized. Tamarack calculates adjusted operating field netback as cash provided by operating activities before the changes in non-cash working capital related to operating activities, abandonment expenditures and transaction costs. The Company's strategy during a period of stable commodity prices is to maintain a ratio of not more than 1.5 times. 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.

With the recent decrease in commodity prices and increased volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by limiting capital spending to projected cash provided by operating activities, using strip 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, 2018, the Company's ratio of net debt to annualized fourth quarter adjusted operating field netback was 1.2 to 1.

($ thousands)	**December 31, 2018**	December 31, 2017
Working capital deficiency	**$18,385**	$9,291
Bank debt	**161,495**	163,889
Net debt	**179,880**	173,180
Quarterly adjusted operating field netback	**$38,346**	$57,583
Annualized factor	**4**	4
Annualized adjusted operating field netback	**153,384**	230,332
Net debt to annualized adjusted operating field netback	**1.2x**	0.8x

There were no changes in the Company's approach to capital management during the year.

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 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 natural gas liquids 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 venture 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, 2018, revenue was earned from customers, of which four customers account for $11.9 million of the accounts receivable at December 31, 2018 (December 31, 2017, 6 customers accounted for $30.8 million of the accounts receivable).

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

	Years ended December 31,	
Years ended December 31, ($ thousands)	**2018**	2017
Light oil	**$322,537**	$215,373
Heavy oil	**11,915**	8,573
Natural gas	**42,978**	41,449
Natural gas liquids	**21,374**	18,277
Oil and natural gas revenue	**$398,804**	$283,672
Processing income	**658**	1,069
Total revenue	**$399,462**	$284,741

Refer to note 5 for a listing of physical delivery contracts as at December 31, 2018.

Included in accounts receivable at December 31, 2018 was $13.8 million (December 31, 2017 - $32.0 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, 2018, 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, 2017	$899,170	$1,034	$900,204
Corporate acquisition	493,200	–	493,200
Cash additions	182,876	334	183,210
Decommissioning costs	43,705	–	43,705
Stock-based compensation	1,997	–	1,997
Transfer from exploration and evaluation assets (note 9)	8,980	–	8,980
Disposals	(5,378)	–	(5,378)
Balance at December 31, 2017	1,624,550	1,368	1,625,918
Property acquisition	2,847	–	2,847
Cash additions	223,102	217	223,319
Decommissioning costs	13,379	–	13,379
Stock-based compensation	3,598	–	3,598
Transfer from exploration and evaluation assets (note 9)	894	–	894
Disposals	(10,215)	–	(10,215)
Balance at December 31, 2018	$1,858,155	$1,585	$1,859,740
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2017	$298,346	$438	$298,784
Depletion and depreciation	147,623	239	147,862
Impairment	17,000	–	17,000
Balance at December 31, 2017	462,969	677	463,646
Depletion and depreciation	176,255	243	176,498
Disposals	(1,037)	–	(1,037)
Impairment, net	5,000	–	5,000
Balance at December 31, 2018	$643,187	$920	$644,107

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2017	$1,161,581	$691	$1,162,272
At December 31, 2018	$1,214,968	$665	$1,215,633

(a) Security:

At December 31, 2018 and 2017, all of the Company’s properties are pledged as security for the bank debt (note 17).

(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, 2018 the Company disposed of its interest in certain oil and gas infrastructure for $9,778 and one non-core, non-producing property for $111 for total proceeds of $9,889. For the year ended December 31, 2017 the Company disposed of its interest in certain oil and gas infrastructure for $5,000 and two non-core, non-producing properties for $301 for total proceeds of $5,301. The Company has entered into operating leases regarding certain oil and gas infrastructure, payments of which is included in commitments (note 19).

(d) Other:

The calculation of depletion at December 31, 2018 includes estimated future development costs of $692,356 (December 31, 2017 – $694,759) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $57,813 (December 31, 2017 – $44,825).

8. Impairment:

(a) 2018 assessment:

Impairment (net of recovery) of $5,000 was recorded as at December 31, 2018 as a result of a decrease in current and forecast natural gas prices. The impairment recognized relates to the Company's Cardium Oil ($58,000) cash-generating unit ("CGU") that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The recoverable amount of this CGU as at December 31, 2018 was estimated to be $330.0 million based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company's independent reserves evaluator at discount rates specific to the underlying composition of reserve categories of 8% to 15% (level 3 inputs). During the years of 2014 and 2015, the Viking Oil CGU was tested for impairment due to decreased oil prices which resulted in the recognition of impairments in the amount of $74,040. As a result of increased reserves and a reduction in future drilling costs per well the Company recognized an impairment reversal in the Viking Oil CGU in the amount of $53,000. The recoverable amount of the Viking Oil CGU as at December 31, 2018 was estimated to be $110.0 million based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company's independent reserves evaluator at discount rates specific to the underlying composition of reserve categories of 8% to 15% (level 3 inputs). The recoverable amounts of the Viking Oil and Cardium Oil CGUs was determined using the fair value less costs of disposal methodology based on what Tamarack could receive for these assets if it disposed of them in the current environment taking into account the increase in the volatility of oil differentials and lower natural gas prices.

The results of Tamarack's impairment tests are sensitive to changes in: quantities of reserves and future production; forward commodity pricing as forecasted by three independent reservoir engineering companies; development costs; operating costs; royalty obligations; abandonment costs; and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in impairment charges or in the reversal of previously recorded impairment charges. As at December 31, 2018, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately $15.0 million to the Cardium

(thousands, except per share and per unit amounts)

Oil CGU and a \$5.0 million change to the impairment reversal of the Viking Oil CGU while a \$1.00/bbl Cdn change to oil prices would result in a change to impairment of approximately \$5.6 million to the Cardium Oil CGU and a \$3.4 million change to the impairment reversal of the Viking Oil CGU. The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2018, as forecasted by the independent external reserves evaluator based on an average of those used by three independent reservoir engineering companies:

	2019	2020	2021	2022	2023	2024	2025	2026	Thereafter
Exchange rate (US\$/Cdn\$[(1)]	0.7567	0.7817	0.7967	0.8033	0.8067	0.8083	0.8083	0.8083	0.8083
WTI (US\$/bbl)[(1)]	58.58	64.60	68.20	71.00	72.81	74.59	76.42	78.40	+2.0%/yr
Edmonton Par (Cdn\$/bbl)[(1)]	67.30	75.84	80.17	83.22	85.34	87.33	89.50	91.89	+2.0%/yr
AECO (Cdn\$/MMbtu)[(1)]	1.88	2.31	2.74	3.05	3.21	3.31	3.39	3.46	+2.0%/yr

(1) Price forecast, effective January 1, 2019.

(b) 2017 assessment:

Impairment of \$17,000 was recorded as at December 31, 2017 as a result of a negative technical reserve revision and a decrease in current and forecast future commodity prices. The impairment recognized relates to the Company's heavy oil (\$13,000) and shallow gas (\$4,000) cash-generating units ("CGUs"). The recoverable amount of these CGU's as at December 31, 2017 was estimated to be \$3,664 for the heavy oil CGU and \$nil for the shallow gas CGU based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company at discount rates in excess of 20% (level 3 inputs). The recoverable amount of Tamarack's CGUs was estimated using the fair value less costs of disposal methodology based on what Tamarack could get for these assets if it disposed of them in the current environment taking into account the increase to heavy oil differentials and lower natural gas prices.

As at December 31, 2017, all else being equal, a 1% increase in the assumed discount rate or a 5% decrease in future planned cash-flows would not significantly affect the impairment expense recognized.

The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2017, as forecasted by the independent external reserves evaluator based on an average of those used by three independent industry reservoir engineering companies:

	2018	2019	2020	2021	2022	2023	2024	2025	Thereafter
Exchange rate (US$/Cdn$)[(1)]	0.7900	0.8000	0.8167	0.8283	0.8400	0.8433	0.8433	0.8433	0.8433
WTI (US$/bbl)[(1)]	57.50	60.90	64.13	68.33	71.19	73.15	75.16	77.17	+2.0%/yr
Edmonton Par (Cdn$/bbl)[(1)]	68.60	72.02	74.48	78.60	80.84	82.83	85.17	87.53	+2.0%/yr
AECO (Cdn$/MMbtu)[(1)]	2.43	2.77	3.19	3.48	3.67	3.76	3.85	3.93	+2.0%/yr

[(1)] Price forecast, effective January 1, 2018.

9. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2017	$23,856
Additions	9,092
Transfer to property, plant and equipment (note 7)	(8,980)
Balance at December 31, 2017	23,968
Additions	2,932
Transfer to property, plant and equipment (note 7)	(894)
Balance at December 31, 2018	$26,006
Accumulated amortization and impairment:	
Balance at January 1, 2017	$21,353
Amortization	787
Balance at December 31, 2017	22,140
Amortization	1,078
Balance at December 31, 2018	$23,218

	Total
Carrying amounts:	
At December 31, 2017	$1,828
At December 31, 2018	$2,788

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

10. 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 $191.3 million at December 31, 2018 (December 31, 2017 – $177.8 million), which is expected to be incurred between 2019 and 2041. A risk-free rate of 2.3% (December 31, 2017 – 2.3%) and an inflation rate of 2% (December 31, 2017 – 2%) is used to calculate the present value of the decommissioning obligations at December 31, 2018 as presented in the table below:

($ thousands)	**December 31, 2018**	December 31, 2017
Balance, beginning of the year	**$177,793**	$112,115
Liabilities incurred	**13,379**	12,689
Liabilities acquired	**–**	19,207
Change in estimates	**–**	1,815
Change in discount rate on acquisition	**–**	29,201
Expenditures	**(1,901)**	(898)
Liabilities disposed	**(374)**	(77)
Accretion	**4,106**	3,741
Balance, end of the year	**$193,003**	$177,793

11. Personnel expenses:

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

Years ended December 31, ($ thousands)	**2018**	2017
Wages and salaries	**$8,443**	$8,867
Benefits and other personnel costs	**1,650**	1,403
Stock-based compensation	**11,797**	5,950
Total employee remuneration	**21,890**	16,220
Capitalized portion of total remuneration	**(7,277)**	(5,342)
	$14,613	$10,878

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 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 and the VP Production and Operations. Executive officers, employees and directors may also participate in the Company's stock option and restricted share unit program. Key executive officers' and directors' compensation is comprised of the following:

Years ended December 31, ($ thousands)	**2018**	2017
Salaries, wages and short-term benefits	**$4,254**	$3,339
Stock-based compensation [(1)]	**5,857**	3,204
	$10,111	$6,543

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

12. Finance expenses:

Years ended December 31, ($ thousands)	2018	2017
Interest on bank debt	**$8,072**	$7,093
Accretion of decommissioning obligations	**4,106**	3,741
	$12,178	$10,834

13. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Years ended December 31, ($ thousands)	2018	2017
Source/(use) of cash:		
Accounts receivable	**$17,462**	$(22,116)
Prepaid expenses and deposits	**725**	(1,726)
Accounts payable and accrued liabilities	**(9,093)**	26,044
Working capital acquired	**–**	29,167
	$9,094	$31,369
Related to operating activities	**$12,098**	$(7,297)
Related to investing activities	**$(3,004)**	$38,666

The following are included in cash flows from operating activities:

Years ended December 31, ($ thousands)	2018	2017
Interest paid in cash	**$8,072**	$7,093

14. Income taxes:

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

Years ended December 31, ($ thousands)	2018	2017
Income (loss) before taxes	**$59,142**	$(17,535)
Expected tax rate	**27.00%**	26.95%
Expected income tax expense (recovery)	**15,968**	(4,726)
Flow-through shares	**–**	(90)
Change in unrecognized deferred tax assets	**101**	(502)
Stock-based compensation	**2,396**	1,175
Change in rates and other	**2,367**	532
Deferred income tax expense (recovery)	**$20,832**	$(3,611)

In 2018, the blended statutory tax rate was 27.00% (December 31, 2017 – 26.95%).

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, ($ thousands)	2018	2017
Deferred tax liabilities:		
Property, plant and equipment	**$(139,706)**	$(134,411)
Financial instruments	**(5,308)**	–
Deferred tax assets:		
Financial instruments	**–**	2,020
Non-capital losses	**37,795**	50,580
Share issue costs	**2,480**	2,469
Decommissioning obligations	**52,112**	47,547
Total	**$(52,627)**	$(31,795)

In calculating the deferred income tax liability in 2018, the Company included $140.5 million (December 31, 2017 - $185.6 million) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2026 and 2036.

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

Years ended December 31, ($ thousands)	2018	2017
Property, plant and equipment	**$17,202**	$16,829

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

($ thousands)	Balance January 1, 2017	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2017
Property, plant and equipment	$(39,483)	$ –	$(94,763)	$5,143	$(765)	$(129,868)
Non-capital losses	49,401	–	11,200	(10,021)	–	50,580
Decommissioning obligations	30,271	–	7,103	10,173	–	47,547
Share issue costs	3,680	5	–	(1,216)	–	2,469
Unrecognized deferred tax assets	(5,045)	–	–	502	–	(4,543)
Financial instruments	2,890	–	100	(970)	–	2,020
Total	$41,714	$5	$(76,360)	$3,611	$(765)	$(31,795)

($ thousands)	Balance January 1, 2018	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2018
Property, plant and equipment	$(129,868)	$ –	$ –	$(5,194)	$ –	$(135,062)
Non-capital losses	50,580	–	–	(12,785)	–	37,795
Decommissioning obligations	47,547	–	–	4,565	–	52,112
Share issue costs	2,469	–	–	11	–	2,480
Unrecognized deferred tax assets	(4,543)	–	–	(101)	–	(4,644)
Financial instruments	2,020	–	–	(7,328)	–	(5,308)
Total	$(31,795)	$ –	$ –	$(20,832)	$ –	$(52,627)

15. Shareholders' equity:

a) Share capital:

At December 31, 2018 and 2017 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

2018:

During the year ended December 31, 2018, 1.7 million stock options at an average price of $3.23 per share were exercised for gross proceeds of $5.4 million. There were also 98,000 restricted share awards converted to common shares.

2017:

On January 11, 2017, the Company issued 90.1 million common shares in connection with the Viking Acquisition.

During the year ended December 31, 2017, 0.8 million stock options at $1.98 per share were exercised for gross proceeds of $1.6 million. There were also 28,000 restricted share awards converted to common shares.

b) Normal course issuer bid:

On April 4, 2018, 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 of the Company between April 6, 2018 and April 5, 2019. During the year ended December 31, 2018, the Company repurchased 3.0 million common shares at an average price of $3.87 per common share, for a total repurchase cost of $11.7 million.

c) Treasury shares:

During the year ended December 31, 2018, the Company spent $5.8 million to purchase 1.8 million common shares to be used to settle restricted share units on the date of exercise. As at December 31, 2018, 1.2 million common shares remain classified as treasury shares to be used for future settlements.

16. Income (loss) per share:

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

($ thousands, except per share amounts)	**2018**	2017
Net income (loss)	**$38,310**	$(13,924)
Weighted average shares - basic	**227,720**	225,306
Weighted average shares - diluted	**233,561**	225,306
Net income (loss) per share-basic	**$ 0.17**	$(0.06)
Net income (loss) per share-diluted	**$ 0.16**	$(0.06)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the year ended December 31, 2018, 10.3 million stock options, preferred shares and restricted share units were included in the diluted weighted average number of shares outstanding. For the year ended December 31, 2017, 11.5 million stock options, preferred shares and restricted stock units were excluded in the diluted weighted average numbers of shares outstanding as they were anti-dilutive.

17. Bank debt:

The Company currently has available a revolving credit facility in the amount of $260 million and a $30 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility, totaling $290 million, lasts for a 364-day period and will be subject to its next 364-day extension by May 24, 2019. If not extended on May 24, 2019, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

During the semi-annual review of the Facility in November 2018, an accordion feature was added to the lending agreement which allows Tamarack to increase the revolving credit facility to $370 million for a total Facility of $400 million, upon exercise and subject to syndicate approval. The accordion feature bears no fees, including standby, until exercised. As at December 31, 2018, the accordion has not been exercised.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and LIBOR Based Loans ("LIBOR") will vary based on a BA/LIBOR pricing grid from a low of the banks' posted rates plus 1.5% to a high of the banks' posted rates plus 3.5%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 0.5% to a high of the banks' prime rates plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.3375% to a high of 0.7875% on the undrawn portion of the Facility. The lending vehicles Tamarack employs from time to time will vary based on capital needs and current market rates. As at December 31, 2018, 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 bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for May 2019.

At December 31, 2018, the Company had utilized the Facility in the amount of $161.5 million. The interest rate applicable to the drawn amounts as of this date was 4.5%. As at December 31, 2018, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility.

There are no financial covenants governing the Facility.

18. Share-based payments:

(a) Preferred share plan:

There are 1,087,000 preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1,045,000 common shares of the Company (December 31, 2017 – 1,111,000). The preferred shares are fully vested at December 31, 2018 and are exchangeable into common shares of the Company 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 preferred shareholders can either (i) elect to receive shares by delivering cash to the Company in the amount of the preferred shares, or (ii) elect to receive a number of shares equivalent to the market value of the preferred shares over the exercise price. For the year ended December 31, 2018 and 2017 there were no preferred shares exercised and 68,000 preferred shares expired.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 15.8 million options or restricted share units to its employees, directors and consultants of which 10.4 million options and restricted share units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 195,000 options granted during the year ended December 31, 2018 (December 31, 2017 – 140,000).

The fair value of each option granted during the years ended December 31, 2018 and 2017 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:

	2018	2017
Risk free rate (%)	**1.94**	1.02
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**1.78**	2.00

The number and weighted average exercise prices of stock options under the plan are as follows:

	Number of options (thousands)	Weighted average exercise price
Outstanding, January 1, 2017	5,327	$ 3.52
Granted	140	3.01
Exercised	(812)	1.98
Expired	(99)	2.79
Outstanding, December 31, 2017	4,556	$ 3.79
Granted	195	2.62
Exercised	(1,682)	3.23
Forfeited	(124)	5.68
Outstanding, December 31, 2018	**2,945**	**$ 3.95**

The range of exercise prices of stock options outstanding and exercisable at December 31, 2018 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
$ 1.86 – 3.00	902	$2.71	2.5	647	$2.73
$ 3.01 – 5.00	1,644	$3.93	1.9	1,296	$4.07
$ 5.01 – 6.82	399	$6.82	0.6	399	$6.82
$ 1.86 – 6.82	**2,945**	**$3.95**	**1.9**	**2,342**	**$4.17**

(c) Restricted share unit plan:

The Company has a restricted share unit plan that allows the Board of Directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted share unit plan, each restricted share award 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 2.4 million restricted share units granted during the year ended December 31, 2018 (December 31, 2017 – 2.8 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. The weighted average fair value of the awards granted for the year ended December 31, 2018 was $4.10 (December 31, 2017 - $2.81). On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards:

	Number of awards (thousands)
Outstanding, January 1, 2017	3,063
Granted	2,785
Exercised	(28)
Forfeited	(2)
Outstanding, December 31, 2017	5,818
Granted	2,378
Exercised	(709)
Forfeited	(80)
Outstanding, December 31, 2018	**7,407**
Exercisable, December 31, 2018	**2,793**

19. Commitments:

The following table summarizes the Company's commitments as at December 31, 2018:

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Office lease	542	263	–	–	–	–	–
Take or pay commitments(1)	2,205	2,256	2,294	2,340	2,396	–	–
Rental fee(2)	6,312	6,312	6,312	4,441	2,570	1,142	1,285
Gas transportation(3)	730	229	76	–	–	–	–
Total	9,789	9,060	8,682	6,781	4,966	1,142	1,285

(1) Pipeline commitment to deliver a minimum of 636 m^3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/$m^3$. The term starts on January 1, 2019 and lasts for 60 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities, rental fee of $0.1 million per month for a maximum period of 96 months starting in January 2016 relating to four facilities, rental fee of $0.05 million per month for a maximum period of 96 months starting in January 2018 relating to one facility and rental fee of $0.05 million per month for a maximum period of 96 months starting in April 2018 relating to one facility.

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

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

David MacKenzie(1)(2)

Jeff Boyce(1)(2)

Noralee Bradley(3)(4)

John Leach(1)(3)

Ian Currie(2)(4)

Rob Spitzer(3)(4)

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 Health, Safety & Environmental Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

McCarthy Tétrault

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

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