MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the years ended December 31, 2018 and 2017. This MD&A is dated and based on information available as at February 26, 2019 and should be read in conjunction with the audited consolidated financial statements and the notes thereto for the years ended December 31, 2018 and 2017. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

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 Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Measures" beginning on page 20. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q4 and Year End 2018 Financial and Operating Highlights

- Maintained stable production volumes of 24,780 boe/d in the fourth quarter relative to 24,765 boe/d in the third quarter, while investing only $25.8 million in capital expenditures, a $52.3 million reduction from the previous quarter.
- Total adjusted operating field netbacks (previously referred to as "adjusted funds flow"; see "Non-IFRS Measures") increased 43% in 2018 to $226.5 million ($0.99 per share basic and $0.97 per share diluted), from $158.4 million in 2017 ($0.70 per share basic and diluted).
- In Q4/18, total adjusted operating field netback of $38.3 million exceeded capital spending of $21.0 million, net of acquisitions and dispositions, by $17.3 million resulting in excess total adjusted operating field netback for the period, which was directed to debt repayment and continued funding of the Company's active share repurchase program.
- Year over year, achieved a 20% increase in production, and an 8% increase in the oil and natural gas liquids ("NGL") weighting percentage, while spending $9 million less, after acquisitions and dispositions, than the Company's previous capital guidance mid-point.

- Full year 2018 net production and transportation expenses per boe were 6% lower relative to 2017, stemming primarily from increased production from the lower-cost Veteran area.
- Tamarack's continued increase in oil and liquids weighting through 2018 largely contributed to 16% higher operating netbacks (see "Non-IFRS Measures") compared to 2017, further supported by improved pricing and lower net production and transportation expenses per boe year over year.
- Invested $219.2 million in total capital expenditures, net of dispositions during 2018, which included drilling a total of 164 (158.2 net) wells, comprised of 129 (124.7 net) Viking oil wells, 19 (17.8 net) Cardium oil wells, four (4.0 net) Penny oil wells, 11 (10.7 net) Redwater oil wells, one exploratory vertical stratigraphic well and one (1.0 net) water source well. In addition to the fourth quarter drilling program, the Company also completed and brought on production wells that were drilled in Q3/18 including 18 (17.8 net) Viking oil wells and one (1.0 net) Penny oil well along with continued development of the Company's waterflood program.

Production

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Production			
Light oil (bbls/d)	**14,163**	14,417	(2)
Heavy oil (bbls/d)	**755**	621	22
Natural gas liquids (bbls/d)	**1,485**	1,403	6
Natural gas (mcf/d)	**50,262**	49,943	1
Total (boe/d)	**24,780**	24,765	–
Percentage of oil and natural gas liquids	**66%**	66%	–

Average production for Q4/18 was consistent with the prior quarter. During the period, the Company added 1,237 boe/d from the Veteran development program (84% oil and NGL), 321 boe/d from the Penny development program (94% oil and NGL), 51 boe/d from the Redwater development program (98% oil and NGL) and 354 boe/d from Wilson Creek/Alder Flats program (69% oil and NGL). These gains were partially offset by expected declines from base production and 98 boe/d that was shut-in due to commodity prices.

In both the fourth and third quarters of 2018, the Company's oil and NGL weighting was 66%. In 2019, the Company expects its oil and NGL weighting to remain stable and average between 64% to 66%. Going forward, Tamarack's liquids weighting will ultimately depend on the timing of production additions from higher oil-weighted areas of Veteran, Wilson Creek, Penny and Redwater relative to additions from the higher natural gas-weighted area of Alder Flats.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Production						
Light oil (bbls/d)	**14,163**	12,189	16	**13,769**	9,929	39
Heavy oil (bbls/d)	**755**	500	51	**552**	511	8
Natural gas liquids (bbls/d)	**1,485**	1,459	2	**1,398**	1,547	(10)
Natural gas (mcf/d)	**50,262**	51,956	(3)	**51,108**	48,893	5
Total (boe/d)	**24,780**	22,807	9	**24,237**	20,136	20
Percentage of oil and natural gas liquids	**66%**	62%	6	**65%**	60%	8

Compared to the prior year, average production for the fourth quarter of 2018 increased by 9% while full year average production increased by 20%. These increases are attributable to the successful development drilling programs at Veteran, Wilson Creek, Penny and Redwater through 2018, partially offset by expected declines from base production.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Revenue ($ thousands)			
Oil and NGL	**$55,962**	$111,636	(50)
Natural gas	**17,113**	7,498	128
Total	**$73,075**	$119,134	(39)
Average realized price			
Light oil ($/bbl)	**36.78**	76.98	(52)
Heavy oil ($/bbl)	**49.33**	69.33	(29)
Natural gas liquids ($/bbl)	**33.72**	43.64	(23)
Combined average oil and NGL ($/boe)	**37.08**	73.81	(50)
Natural gas ($/mcf)	**3.70**	1.63	127
Revenue ($/boe)	**32.05**	52.29	(39)
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**58.79**	69.54	(15)
Edmonton Par (Cdn$/bbl)	**48.26**	77.26	(38)
Hardisty Heavy (Cdn$/bbl)	**34.23**	54.34	(37)
AECO daily index (Cdn$/mcf)	**1.55**	1.18	31
AECO monthly index (Cdn$/mcf)	**1.89**	1.35	40

Revenue from oil, natural gas and NGL sales was 39% lower in the fourth quarter of 2018 compared to the third quarter of 2018, entirely attributable to the sudden and extreme widening of price differentials for Canadian crude that occurred in the period. The abnormally wide differentials resulted in decreased wellhead pricing for crude oil and NGL, which was partially offset by higher natural gas pricing in the quarter.

WTI crude oil markets fell significantly in the fourth quarter of 2018, reaching a 2018 low with a spot price of US$42.68/bbl in the month of December. The average fourth quarter WTI price of US$58.79/bbl was 15% lower than the average third quarter price of US$69.54/bbl. In addition, the WTI/Edmonton Par light oil differential exploded in Q4/18 to reach a high of US$37.19/bbl and averaging US$29.30/bbl versus US$6.82/bbl in Q3/18. These factors compounded to decimate pricing for Canadian crude oil, including the light sweet market, causing the average Edmonton Par price to decrease 38% to $48.26/bbl versus the third quarter average of $77.26/bbl. Additionally, Tamarack's realized light oil wellhead price for the three months ended December 31, 2018 decreased 52% to $36.78/bbl from $76.98/bbl in the previous quarter. Due to continued issues related to market oversupply and Canadian infrastructure restrictions, the Government of Alberta announced production curtailments that took effect January 1, 2019. These curtailments, combined with active production management and engagement from the producer community, have resulted in a significant narrowing of the differential into the early part of 2019. Although this narrowing is a positive development, Tamarack believes the differential poses a significant risk to Canadian crude prices in 2019. Tamarack currently has approximately 30% of forecasted 2019 oil production protected with differential hedges. While the timing, duration and magnitude of extreme oil price conditions are difficult to predict, Tamarack is committed to conservatively planning and continues to explore ways to mitigate and manage market risk through financial and physical hedges.

The decrease in WTI prices through the quarter also impacted NGL prices, namely butane and condensate, as these contracts are priced relative to WTI, contributing to the lower average NGL price for the quarter. Realized NGL prices decreased 23% in Q4/18 to $33.72/bbl from $43.64/bbl in Q3/18. Similar to other products in the Alberta market, NGL supply currently outstrips demand. In particular, Alberta butane markets cratered significantly through the last six months of 2018. Given the majority of Tamarack's butane contracts are set as a percentage of WTI at the beginning of the contract year (April 1), to date the Company has not experienced material effects related to this weakness. If these market conditions persist, NGL prices could decrease significantly through the next contract year, which begins April 1, 2019.

Somewhat offsetting the oil and NGL price impacts during Q4/18, Tamarack's realized natural gas price increased significantly in the fourth quarter to $3.70/mcf compared to $1.63/mcf in Q3/18. To a lesser degree, the AECO daily benchmark price also increased quarter-over-quarter to $1.55/mcf from $1.18/mcf. These changes were due largely to higher winter season gas prices, with Tamarack's exposure to Eastern US gas markets specifically benefitting the Company's realized price.

Tamarack's exposure to various gas markets and pricing hubs is reflected below:

Natural Gas Market	**Percentage Exposure (as at December 31, 2018)**
AECO Daily (5A)	0.4
AECO Daily (5A) + premium (SK)	21.7
Dawn	8.9
Chicago	8.9
Michigan City Gate	8.9
Malin	17.7
Waddington	11.3
NYMEX (Physical Basis Swap)	22.2
	100%

Oversupply and takeaway capacity restrictions continue to create downward pricing pressure and volatility in Alberta natural gas markets. Despite increased usage across the colder winter months, AECO daily index pricing is expected to remain depressed through 2019 and beyond. Tamarack continues to benefit from multiple third-party gas sales contracts featuring time horizons for varying end dates up to 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate volatility risk in any individual market. Through the fourth quarter of 2018, more than 50% of Tamarack's total natural gas production was priced at alternate US markets, including Malin, Chicago, Michigan Consolidated, Dawn and NYMEX daily index pricing less transportation tolls or fixed basis fees. Tamarack will continue to explore alternatives to minimize exposure to the historically weaker Alberta natural gas market.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Revenue ($ thousands)						
Oil and NGL	**$55,962**	$81,139	(31)	**$355,826**	$242,223	47
Natural gas	**17,113**	9,021	90	**42,978**	41,449	4
Total	**$73,075**	$90,160	(19)	**$398,804**	$283,672	41
Average realized price						
Light oil ($/bbl)	**36.78**	65.08	(43)	**64.17**	59.42	8
Heavy oil ($/bbl)	**49.33**	48.97	1	**59.13**	46.01	29
Natural gas liquids ($/bbl)	**33.72**	44.03	(23)	**41.89**	32.38	29
Combined average oil and NGL ($/boe)	**37.08**	62.34	(41)	**62.02**	55.36	12
Natural gas ($/mcf)	**3.70**	1.89	96	**2.30**	2.32	(1)
Revenue ($/boe)	**32.05**	42.97	(25)	**45.08**	38.60	17
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**58.79**	55.39	6	**64.78**	51.00	27
Edmonton Par (Cdn$/bbl)	**48.26**	66.86	(28)	**69.14**	62.23	11
Hardisty Heavy (Cdn$/bbl)	**34.23**	48.69	(30)	**49.95**	49.42	1
AECO daily index (Cdn$/mcf)	**1.55**	1.68	(8)	**1.49**	2.14	(30)
AECO monthly index (Cdn$/mcf)	**1.89**	1.95	(3)	**1.52**	2.41	(37)

Revenue from oil, natural gas and NGL sales for Q4/18 decreased 19% compared to the same period in 2017, primarily due to lower oil and NGL prices, partially offset by increased production volumes, an increase in oil weighting and an increase in realized natural gas prices.

For the year ended December 31, 2018, revenue from oil, natural gas and NGL sales increased 41% compared to the same period in 2017, primarily due to increased production volumes, increased oil weighting and higher oil and NGL prices.

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. 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
Crude oil	400 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $63.10
Crude oil	700 bbls/day	April 1, 2019 – June 30, 2019	WTI fixed price	US $65.45
Crude oil	700 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $66.96
Crude oil	4,140 bbls/day	January 1, 2019 – March 31, 2019	WTI put option	US $60.00
Crude oil	3,220 bbls/day	April 1, 2019 – June 30, 2019	WTI put option	US $60.00
Crude oil	3,105 bbls/day	July 1, 2019 – September 30, 2019	WTI put option	US $60.00
Crude oil	2,990 bbls/day	October 1, 2019 – December 31, 2019	WTI put option	US $60.00
Crude oil	4,000 bbls/day	January 1, 2019 – December 31, 2019	Edm par diff	US $12.13
Foreign exchange	6,750,000 US$/mth	January 1, 2019 – March 31, 2019	Exchange rate	Cdn $1.3074
Foreign exchange	6,750,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.3046
Foreign exchange	5,750,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3065
Foreign exchange	4,750,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.3111

At December 31, 2018, the commodity and foreign exchange contracts were fair valued with an asset value of $19.7 million (December 31, 2017 - $7.5 million liability) recorded on the balance sheet and an unrealized gain of $27.1 million recorded in earnings for the year ended December 31, 2018 (December 31, 2017 - $3.5 million unrealized gain). During Q4/18, the Company realized a $0.1 million gain on financial instruments and a $17.9 million loss for the year ended December 31, 2018, compared to a gain of $3.2 million and $5.6 million for the same periods in 2017, respectively.

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

Since December 31, 2018, the Company has entered into the following 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.

Royalties

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Royalty expenses ($ thousands)	**$5,902**	$12,075	(51)
$/boe	**2.59**	5.30	(51)
percent of sales	**8**	10	(20)

Royalties as a percentage of revenue were lower in the fourth quarter of 2018 compared to the third quarter of 2018, largely caused by two factors: the sliding scale nature of some oil royalties which lowers the percent royalty paid when commodity prices are low; and an increased contribution of volumes from newly drilled locations on crown lands where royalty rates are fixed at 5% for an initial capital recovery period.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Royalty expenses ($ thousands)	**$5,902**	$8,464	(30)	**$39,901**	$29,134	37
$/boe	**2.59**	4.03	(36)	**4.51**	3.96	14
percent of sales	**8**	9	(11)	**10**	10	–

Royalties as a percentage of revenue were comparable for both the three months and year ended December 31, 2018 compared to the same periods in 2017. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for 2019 based on the current forecast commodity price levels.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Production and transportation expenses	**$24,291**	$23,813	2
Less: processing income	**426**	170	151
Total net production and transportation expenses	**$23,865**	$23,643	1
Total ($/boe)	**$10.47**	$10.38	1

Net production and transportation expenses per boe for the fourth quarter of 2018 increased 1% compared to the third quarter of 2018. On an absolute basis, overall costs were marginally higher in the fourth quarter of 2018 compared to the third quarter of 2018 related to an increase in workovers offset by lower transportation costs due to the start-up of a midstream company's new 120 km pipeline (the "Viking Pipeline Project") which occurred in December, 2018.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Production and transportation expenses	**$24,291**	$22,191	9	**$93,683**	$83,308	12
Less: processing income	**426**	373	14	**658**	1,069	(38)
Total net production and transportation expenses	**$23,865**	$21,818	9	**$93,025**	$82,239	13
Total ($/boe)	**$10.47**	$10.40	1	**$10.52**	$11.19	(6)

For the three months ended December 31, 2018, net production and transportation expenses per boe were comparable to the same period in 2017.

For the year ended December 31, 2018, net production and transportation expenses per boe were lower relative to the same period in 2017 as a result of increased production volumes from the Veteran area, where production expenses are lower than the corporate average. In addition, higher volumes spread across fixed costs results in lower per boe costs. On an absolute basis, net production and transportation expenses increased due to higher production volumes generated over the period.

Tamarack entered into a commitment agreement on a take-or-pay basis to deliver at least 4,000 bbls/d of oil to the Viking Pipeline Project. The Viking Pipeline Project will extend the reach of the existing Provost pipeline and support Tamarack's planned development of the Veteran Viking oil play by ensuring the Company has access to oil markets. The Viking Pipeline Project has initial capacity of 13,300 bbls/d and the potential to expand up to 25,000 bbls/d. This contract will eliminate the need for Tamarack to truck oil sales to markets and is anticipated to reduce Veteran operating costs by approximately $1.45/boe contributing to corporate production and transportation cost savings of approximately $0.40 to $0.50/boe in 2019.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q4 2018**	Q3 2018	% change
Average realized sales	**$32.05**	$52.29	(39)
Royalty expenses	**(2.59)**	(5.30)	(51)
Net production and transportation expenses	**(10.47)**	(10.38)	1
Operating field netback	**18.99**	36.61	(48)
Realized commodity hedging gain (loss)	**0.04**	(4.16)	(101)
Operating netback	**$19.03**	$32.45	(41)

As a result of the oil price dynamics that transpired during Q4/18 discussed above, the Company's operating netbacks (see "Non-IFRS Measures") for the period decreased 41% compared to the prior quarter. This decrease stems from a combination of lower wellhead pricing for crude oil and NGL, partially offset by an increase in realized natural gas pricing, a decrease in royalties and a realized commodity hedging gain compared to a realized hedging loss in the previous quarter.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2018**	2017	% change	**2018**	2017	% change
Average realized sales	**$32.05**	$42.97	(25)	**$45.08**	$38.60	17
Royalty expenses	**(2.59)**	(4.03)	(36)	**(4.51)**	(3.96)	14
Net production and transportation expenses	**(10.47)**	(10.40)	1	**(10.52)**	(11.19)	(6)
Operating field netback	**18.99**	28.54	(33)	**30.05**	23.45	28
Realized commodity hedging gain (loss)	**0.04**	1.53	(97)	**(2.03)**	0.77	(364)
Operating netback	**$19.03**	$30.07	(37)	**$28.02**	$24.22	16

Similarly, Q4/18 operating netbacks decreased 37% over the same period in 2017 due to the lower wellhead pricing for crude oil and NGL as discussed above and a lower realized commodity hedging gain. These losses were partially offset by higher realized natural gas prices and lower royalties.

For the year ended December 31, 2018, operating netbacks increased 16% over the same period in 2017, supported by the Company's higher oil and NGL weighting, higher wellhead pricing for crude oil and NGL and lower net production and transportation expenses per boe. These gains were partially offset by a realized commodity hedging loss on financial derivative contracts in 2018 and higher royalties.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Gross costs	**$4,272**	$4,377	(2)
Capitalized costs and recoveries	**(934)**	(1,082)	(14)
General and administrative costs	**$3,338**	$3,295	1
Total ($/boe)	**$1.46**	$1.45	1

Gross and net G&A expenses remained consistent between the fourth quarter of 2018 and the third quarter of 2018. G&A expenses on a per boe basis remained consistent quarter-over-quarter.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Gross costs	**$4,272**	$4,257	–	**$17,064**	$15,807	8
Capitalized costs and recoveries	**(934)**	(842)	11	**(3,678)**	(3,345)	10
General and administrative costs	**$3,338**	$3,415	(2)	**$13,386**	$12,462	7
Total ($/boe)	**$1.46**	$1.63	(10)	**$1.51**	$1.70	(11)

Gross G&A costs increased for the year ended December 31, 2018, compared to the same period in 2017, due to higher staffing levels required to effectively manage the increase in production. Net per boe G&A costs for both the three months and year ended December 31, 2018 were lower than the same periods in 2017 due to scale efficiencies associated with the increase in production.

Stock-Based Compensation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Gross costs	**$4,040**	$4,175	(3)
Capitalized costs	**(1,140)**	(1,177)	(3)
Total stock-based compensation	**$2,900**	$2,998	(3)
Total ($/boe)	**$1.27**	$1.32	(4)

Stock-based compensation expense related to stock options ("options") and restricted share unit awards ("RSUs") was similar in Q4/18 as Q3/18. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year

($ thousands, except per boe)	Three months ended December 31, 2018	2017	% change	Years ended December 31, 2018	2017	% change
Gross costs	**$4,040**	$1,618	150	**$12,471**	$6,357	96
Capitalized costs	**(1,140)**	(481)	137	**(3,598)**	(1,997)	80
Total stock-based compensation	**$2,900**	$1,137	155	**$8,873**	$4,360	104
Total ($/boe)	**$1.27**	$0.54	135	**$1.00**	$0.59	69

Stock-based compensation expense related to options and restricted share units ("RSU") was higher for the three months and year ended December 31, 2018 relative to the same periods in 2017, as higher staffing levels stemming from Tamarack's production growth through 2017 resulted in more RSU being granted at the end of the fourth quarter of 2017 and the second quarter of 2018. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

For the year ended December 31, 2018, the Company issued 0.2 million options at a weighted average exercise price of $2.62 per share and issued 2.4 million RSU.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	Q4 2018	Q3 2018	% change
Interest on bank debt	**$1,706**	$2,063	(17)
Total ($/boe)	**$0.75**	$0.91	(18)
Average drawings on bank debt	**$159,286**	$155,131	3

Interest expense was lower in the fourth quarter of 2018 compared to the previous quarter, due to the increased utilization of lower interest rate options that were available through the Company's syndicate of lenders as well as favourable market conditions at year end.

Year-over-Year

($ thousands, except per boe)	Three months ended December 31, 2018	2017	% change	Years ended December 31, 2018	2017	% change
Interest on bank debt	**$1,706**	$2,097	(19)	**$8,072**	$7,093	14
Total ($/boe)	**$0.75**	$1.00	(25)	**$0.91**	$0.97	(6)
Average drawings on bank debt	**$159,286**	$175,373	(9)	**$158,898**	$150,873	5

Interest expense for the three months ended December 31, 2018 was lower than the same period in 2017 due to a lower average amount drawn on the revolving credit facility.

Interest expense for the year ended December 31, 2018 was higher than the same period in 2017. This is attributable to an interest rate increase that occurred at the beginning of the third quarter of 2018, coupled with a higher average amount drawn on the revolving credit facility during 2018, associated with the Company's increased capital spending year-over-year.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

The Company depletes its property, plant and equipment ("PP&E") based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation ("E&E") assets is also amortized over its term to expiry, which is charged to DDA&A expense.

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Depletion and depreciation	**$44,498**	$45,409	(2)
Amortization of undeveloped leases	**328**	282	16
Accretion	**1,043**	1,041	-
Total	**$45,869**	$46,732	(2)
Depletion and depreciation ($/boe)	**$19.52**	$19.93	(2)
Amortization ($/boe)	**0.14**	0.12	17
Accretion ($/boe)	**0.46**	0.46	-
Total ($/boe)	**$20.12**	$20.51	(2)

DDA&A expense per boe for the fourth quarter of 2018 was lower compared to the third quarter of 2018. This decrease is due to the completion of the Company's year-end independent reserve evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2018 drilling program, better-than-expected well performance and additional reserves being added as a result of the Veteran waterflood project. On an absolute basis, DDA&A expense was lower due to the lower DDA&A expense per boe.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Depletion and depreciation	**$44,498**	$41,569	7	**$176,498**	$147,862	19
Amortization of undeveloped leases	**328**	197	66	**1,078**	787	37
Accretion	**1,043**	1,035	1	**4,106**	3,741	10
Total	**$45,869**	$42,801	7	**$181,682**	$152,390	19
Depletion and depreciation ($/boe)	**$19.52**	$19.81	(1)	**$19.95**	$20.12	(1)
Amortization ($/boe)	**0.14**	0.09	56	**0.12**	0.11	9
Accretion ($/boe)	**0.46**	0.49	(6)	**0.46**	0.51	(10)
Total ($/boe)	**$20.12**	$20.39	(1)	**$20.53**	$20.74	(1)

For the three months and year ended December 31, 2018, DDA&A expense per boe was slightly lower relative to the same periods in 2017. The decrease was due to the completion of the Company's year-end independent reserve evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2018 drilling program, better-than-expected well performance and additional reserves being added as a result of the Veteran waterflood project. On an absolute basis, DDA&A expense was higher for the three months and year ended December 31, 2018 due to an increase in production volumes.

Income Taxes

The Company did not incur any cash tax expense in the three months or year ended December 31, 2018, nor does it expect to pay any cash tax in 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2018, deferred income tax expense of $11.5 million and $20.8 million, respectively, were recognized compared to a deferred income tax recovery of $4.3 million and $3.6 million for the same respective periods in 2017.

The following table outlines the Company's estimated tax pools as at December 31, 2018:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	33
Canadian development expense (CDE)	30%	334
Canadian oil and gas property expense (COGPE)	10%	230
Non-capital losses (NCL)	100%	141
Undepreciated capital cost (UCC)	25%	131
Share issue costs and other	various	9
Total		878

Adjusted Operating Field Netback and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q4 2018**	Q3 2018	% change
Income before taxes	**$30,415**	$18,923	61
Depletion, depreciation and amortization	**44,826**	45,691	(2)
Stock-based compensation	**2,900**	2,998	(3)
Gain on disposition of property, plant and equipment	**(1,079)**	–	–
Accretion expense on decommissioning obligations	**1,043**	1,041	–
Unrealized gain on financial instruments	**(44,759)**	(74)	60,385
Impairment of property, plant and equipment, net	**5,000**	–	–
Adjusted operating field netback	**$38,346**	$68,579	(44)
Per share - basic	**$0.17**	$0.30	(43)
Per share - diluted	**$0.17**	$0.29	(41)
Net income	**$18,952**	$13,004	46
Per share - basic	**$0.08**	$0.06	33
Per share - diluted	**$0.08**	$0.06	33

The adjusted operating field netback (see "Non-IFRS Measures") during the fourth quarter of 2018 was lower than the third quarter of 2018 primarily due to 39% lower revenue from oil and natural gas sales caused by the extremely weak Canadian oil price market during the period, partially offset by a realized hedging gain in Q4/18 compared to a realized hedging loss in Q3/18.

The Company recorded increased net income of $19.0 million ($0.08 per share basic and diluted) during the three months ended December 31, 2018, compared to net income of $13.0 million ($0.06 per share basic and diluted) for the previous quarter. This was primarily due to a higher unrealized hedging gain in Q4/18 compared to Q3/18, partially offset by 39% lower revenue from oil and natural gas sales, higher deferred tax expense and a net impairment to property, plant and equipment.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per share)	**2018**	2017	% change	**2018**	2017	% change
Income (loss) before taxes	**$30,415**	$(16,851)	(280)	**$59,142**	$(17,535)	(437)
Depletion, depreciation and amortization	**44,826**	41,766	7	**177,576**	148,649	19
Stock-based compensation	**2,900**	1,137	155	**8,873**	4,360	104
Gain on disposition of property, plant and equipment	**(1,079)**	–	–	**(1,085)**	–	–
Transaction costs	**–**	–	–	**–**	5,663	(100)
Accretion expense on decommissioning obligations	**1,043**	1,035	1	**4,106**	3,741	10
Unrealized loss (gain) on financial instruments	**(44,759)**	13,496	(432)	**(27,137)**	(3,495)	676
Impairment of property, plant and equipment, net	**5,000**	17,000	(71)	**5,000**	17,000	(71)
Adjusted operating field netback	**$38,346**	$57,583	(33)	**$226,475**	$158,383	43
Per share - basic	**$0.17**	$0.25	(32)	**$0.99**	$0.70	41
Per share - diluted	**$0.17**	$0.25	(32)	**$0.97**	$0.70	39
Net income (loss)	**$18,952**	$(12,525)	(251)	**$38,310**	$(13,924)	(375)
Per share - basic	**$0.08**	$(0.05)	(260)	**$0.17**	$(0.06)	(383)
Per share - diluted	**$0.08**	$(0.05)	(260)	**$0.16**	$(0.06)	(367)

Fourth quarter 2018 adjusted operating field netback (see “Non-IFRS Measures”) was lower on an absolute basis than the same period in 2017, primarily due to lower crude oil prices.

For the full year 2018, adjusted operating field netback (see “Non-IFRS Measures”) was higher on an absolute basis than the same period in 2017, primarily due to increased production, higher crude oil prices and operating netbacks. The increase in operating netbacks was related primarily to the increase in oil and NGL weighting and the reduction in net production and transportation expenses per boe.

The Company recorded net income of $19.0 million ($0.08 per share basic and diluted) and $38.3 million ($0.17 per share basic and $0.16 per share diluted) during the three months and year ended December 31, 2018, respectively, compared to a net loss of $12.5 million ($0.05 per share basic and diluted) and $13.9 million ($0.06 per share basic and diluted) for the same periods in 2017. This was primarily due to increased production, higher crude oil prices and operating netbacks, the unrealized hedging gains that occurred in 2018, partially offset by deferred tax expense and higher depletion, depreciation and amortization charges.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

The following table summarizes capital spending, excluding non–cash items:

	Three months ended December 31,			Years ended December 31,		
($ thousands)	**2018**	2017	% change	**2018**	2017	% change
Land	**$42**	$(174)	(124)	**$4,690**	$1,708	175
Geological and geophysical	**–**	–	–	**13**	2,022	(99)
Drilling and completion	**15,254**	26,378	(42)	**167,216**	143,802	16
Equipment and facilities	**9,664**	8,591	12	**51,254**	41,766	23
Capitalized G&A	**791**	687	15	**2,861**	2,670	7
Office equipment	**47**	34	38	**217**	334	(35)
Total capital expenditures	**$25,798**	$35,516	(27)	**$226,251**	$192,302	18

In response to the rapid and extreme widening of Canadian oil price differentials that occurred in Q4/18, Tamarack elected to defer $7.0 million of the $28.4 million in capital spending that had previously been planned for acceleration from 2019 into Q4/18. As a result, the Company's Q4/18 capital spending totaled $25.8 million, bringing its total annual capital investment to $226.3 million ($219.2 million net of acquisitions and dispositions). During the fourth quarter of 2018, the Company drilled, completed and equipped five (4.8 net) Viking oil wells plus one water source well in the Veteran area. In addition to the fourth quarter drilling program, the Company also completed and brought on production wells that were drilled in late Q3/18 including 18 (17.8 net) Viking oil wells and one (1.0 net) Penny oil well. The Company also drilled 19 (18.5 net) Viking oil wells that will be brought on production in the first quarter of 2019, resulting in total drilling for the quarter of 24 (23.2 net) Viking oil wells and one (1.0 net) water source well.

Tamarack also directed capital to the continued development of a waterflood program in the Company's Veteran, Alberta area. Of the 24 Viking oil wells drilled at Veteran in the quarter, six wells are future injection wells, which will produce to recover the capital costs until the commencement of the injection project in the first half of 2019. Additionally, significant investment in area pipeline and facility infrastructure that is required to operate the infield waterflood was initiated and continued through the end of 2018 and into early 2019. The waterflood project is designed to improve oil recoveries, reduce corporate decline rates and increase production rates while utilizing existing owned infrastructure. These supplementary projects are subject to the same rate of return thresholds as those used for development drilling when competing for capital.

	2018 Drilling Summary		2017 Drilling Summary	
	Gross	Net	Gross	Net
Viking	129.0	124.7	104.0	99.0
Cardium	19.0	17.8	16.0	15.3
Redwater	11.0	10.7	4.0	3.1
Penny	4.0	4.0	1.0	1.0
Other	1.0	1.0	8.0	8.0
	164.0	158.2	133.0	126.4

As at December 31, 2018, the Company's net undeveloped land totaled 413,008 acres.

Property Acquisitions and Dispositions

In the fourth quarter of 2018, Tamarack completed two dispositions for total proceeds of $4.9 million. No production was associated with these disposed assets.

During the year ended December 31, 2018, Tamarack completed one tuck-in acquisition for $2.8 million and three dispositions for proceeds of $9.9 million. The acquisition added 18 boe/d and 3.3 (2.1 net) sections of undeveloped land. The disposed assets did not have any associated production.

Impairment

An impairment charge (net of recovery) of $5.0 million (December 31, 2017 – $17.0 million) was recorded as at December 31, 2018 on the Company's PP&E. The impairment charge is primarily the result of a decrease in current and forecast natural gas prices. The impairment recognized relates to the Company's Cardium Oil ($58.0 million) 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 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%. There was also an impairment reversal in the Viking Oil CGU in the amount of $53.0 million due to increased reserves and a reduction in future drilling costs per well and was 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%. During the years of 2014 and 2015 the Viking Oil CGU was tested for impairment due to decreased oil prices which resulted in impairments in the amount of $74.0 million. The recoverable amount of Tamarack's 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 to the volatility of oil differentials and lower natural gas prices.

Share Capital

At December 31, 2018, Tamarack had 226,072,693 common shares, 1,193,188 common shares held in treasury, 2,944,833 options and 7,407,472 RSU outstanding. At February 26, 2019, there were 226,348,750 common shares, 819,731 common shares held in treasury, 2,944,833 options and 7,074,015 RSUs outstanding. This compares to December 31, 2017, at which time there were 228,510,381 common shares, 4,555,667 options and 5,818,382 RSU outstanding. No preferred shares of Tamarack are issued and outstanding.

At December 31, 2018, there were 1,086,974 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,045,168 common shares of the Company and at December 31, 2017, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. which were exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at December 31, 2018 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share. For the year ended December 31, 2018, 68,033 TAC Preferred Shares expired.

As noted under 'Liquidity and Capital Resources' below, during the year ended December 31, 2018, Tamarack purchased and cancelled 3,025,000 outstanding common shares under its normal course issuer bid ("NCIB") program, for a total investment of $11.7 million. The NCIB provides management with an instrument that can be employed when there is a perceived misalignment between the Company's prevailing share price and the underlying current and future potential value of its assets. In addition to supporting the Company's commitment to generating per share value, the NCIB also helps to offset the potential for dilutive impact that may be associated with the exercise and settlement of options issued under

Tamarack's stock-based compensation program.

Over and above the NCIB, during the year ended December 31, 2018, the Company also directed $5.8 million to the purchase of 1,803,592 outstanding common shares in the open market. Once purchased, these shares are held in trust by Tamarack's trustee and used to settle RSUs upon future exercise. This practice mitigates dilution by eliminating the need to issue new shares from treasury for the settlement of RSUs. Instead, Tamarack has the ability, when needed, to 'draw down' from the remaining balance of purchased shares that are held in trust to settle RSU exercises, further supporting Tamarack's per share metrics. At December 31, 2018, the balance of the remaining common shares held in trust totaled 1,193,188.

Liquidity and Capital Resources

($ thousands)	**December 31, 2018**	December 31, 2017	September 30, 2018
Working capital deficiency	**$18,385**	$9,291	$23,214
Bank debt	**161,495**	163,889	168,970
Net debt	**179,880**	173,180	192,184
Quarterly adjusted funds flow	**$38,346**	$57,583	$68,579
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**153,384**	230,332	274,316
Net debt to annualized adjusted funds flow	**1.2x**	0.8x	0.7x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency but excluding the fair value of financial instruments, totaled $179.9 million as at December 31, 2018. This compares to net debt of $192.2 million and $173.2 million in the previous quarter and the fourth quarter of 2017, respectively. Tamarack's Q4/18 net debt to annualized adjusted operating field netback ratio was 1.2 times.

The $21.0 million of capital expenditures and property acquisitions, net of dispositions, invested during the fourth quarter of 2018 was funded entirely by Tamarack's adjusted operating field netback of $38.3 million. The excess $17.3 million adjusted operating field netback, plus the $0.5 million proceeds from exercised options, funded the $2.3 million of share purchases under the NCIB, $1.8 million of shares purchased to be held in treasury to offset future dilution from potential RSU settlements, $1.5 million of abandonments and the remaining $12.3 million reduced net debt.

The $219.2 million of capital expenditures and property acquisitions, net of dispositions, invested during the year ended December 31, 2018 was funded entirely by Tamarack's adjusted operating field netback of $226.5 million. The excess $7.3 million adjusted operating field netback, plus $5.4 million in proceeds from exercised options and $6.7 million of increased net debt, collectively funded the $11.7 million of share purchases under the NCIB, $5.8 million of shares purchased to be held in treasury to offset future dilution from potential RSU settlements and $1.9 million of abandonments.

With continued commodity price volatility and crude oil price differential volatility recently impacting the Canadian oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by adjusting capital spending as appropriate to respond to changes in realized commodity prices and by using financial derivatives and physical delivery contracts to mitigate risk. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas, whether by increasing drilling activity or by completing tuck-in acquisitions. Although Tamarack's business remains solid, at times management believes the Company's prevailing share price does not adequately reflect the underlying value of its assets.

As such, Tamarack implemented the NCIB through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company would have the option to repurchase its common shares for cancellation, thereby reducing the total number of shares outstanding. The NCIB represents an additional tool that can be employed as part of management's ongoing strategy to increase long-term shareholder value. As of December 31, 2018, the Company spent $11.7 million to purchase and cancel 3,025,000 outstanding common shares under the NCIB.

Further, the Company remains committed to executing its proven strategy of focusing on drilling wells that target a return on capital cost payout of 1.5 years or less, and will continue to control or reduce capital, production and transportation costs where possible. "Capital cost payout" or "payout" are Non-IFRS measures and are achieved when revenues, less royalties, production and transportation costs are equal to the total capital costs associated with drilling, completing, equipping and tying-in a well (see "Non-IFRS Measures").

Bank Debt

Tamarack 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 totals $290 million, of which $161.5 million is drawn as of December 31, 2018 (December 31, 2017 - $163.9 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 that occurred in the fourth quarter of 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 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.

There are no financial covenants governing the Facility.

Guidance

Tamarack's fourth quarter production averaged 24,780 boe/d (oil and NGL weighting of 66%) which was in line with its exit guidance range of 24,500 to 25,000 boe/d (oil and NGL weighting 65 to 67%). Average annual production for 2018 of 24,237 boe/d was also in line with guidance of 24,000 to 24,500 boe/d (64 to 66% oil and NGL) despite spending $219 million, net of acquisitions and dispositions, which was $9 million less than the mid-point of guidance.

Tamarack's capital allocation strategy over the past several years has remained consistent with the objective of achieving sustainability at low oil prices, while generating debt-adjusted per share growth. Due to the Company's success in accumulating an inventory of Viking and Cardium locations that payout in 1.5 years or less at current commodity prices, Tamarack expects to be fully self-funding in 2019 and estimates it will achieve 3-5% debt-adjusted production per share[1] growth (see "Non-IFRS Measures") in Q4/19 over Q4/18. The Company remains well positioned to withstand further crude oil price volatility given approximately 30% of its 2019 production is protected with hedges that include a US$60.00/bbl WTI put option with another approximately 3% protected by fixed price contracts at US$64.60/bbl.

Tamarack plans to invest between $170 and $180 million in its 2019 capital expenditures, funded entirely through adjusted operating field netback. This capital program is expected to result in stable year over year average production of 23,500 – 24,500 boe/d (oil and NGL weighting 64 to 66%), while spending approximately 23% less than in 2018. The Company's 2019 budget anticipates drilling 125 net wells, including 110 Viking light oil wells (94 of which will be at Veteran), 13 Cardium light oil wells and two wells at Penny. In addition, the 2019 budget includes $19.8 million of waterflood investments, including 15 well conversions in H1/19 and the drilling and conversion of six additional injection wells in East Veteran. In the context of continued volatility in oil prices and supported by the Company's exceptional operational execution, Tamarack remains committed to investing in longer-term projects, including the Veteran waterflood, which the Company expects will reduce the overall corporate decline rate in 2020 and further enhance Tamarack's sustainability.

Effective January 1, 2019, the Alberta government imposed mandatory oil curtailments designed to mitigate the wide price differential related to a lack of pipeline capacity, which is ultimately expected to lead to stronger oil prices. While the Company's 2019 capital guidance assumes activity levels will be weighted evenly between the first and second halves of 2019, the timing of capital allocation in H1/19 has been designed to comply with the required production cuts. As a result, approximately 65% of the drilling program will occur in the H2/19. Following expected stable production levels in H1/19 stemming from the mandatory volume curtailments, Tamarack anticipates realizing a meaningful ramp-up in production volumes during H2/19, assuming no additional government intervention.

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[1] Debt-adjusted production per share is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt adjusted share count is calculated as total shares outstanding plus incremental shares issued using $2.30 per share to eliminate the change in net debt or in the case where net debt decreases the reduction in shares using the same $2.30 per share.

The Company's 2019 budget is summarized in the following table:

	2019 Budget
Average annual production (boe/d)	23,500 – 24,500
Liquids weighting (%)	~64 - 66
Exit production (boe/d)	25,500 – 26,500
Liquids weighting (%)	~64 – 66
2019 Capital expenditures ($millions)	$170 - $180
2019 price assumptions:	
WTI ($US/bbl)	$50.00
Edmonton Par ($CDN/bbl)	$52.33
Edmonton Par differential ($US/bbl)	$10.75
AECO ($CDN/GJ)	$1.31
Canadian/US dollar exchange rate	$0.75

Should forecasted realized commodity prices significantly fluctuate from levels outlined in the assumptions above, Tamarack maintains control to accelerate or reduce capital expenditures, redirect capital to purchase shares through the NCIB program or pay down debt.

Commitments

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

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Bank debt	-	161,495	–	–	–	–	–
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	170,555	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.

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Administrators' National Instrument 51–101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Boe may be misleading, particularly if used in isolation.

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	gigajoule
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
Mmbtu	one million British thermal units
NGL	natural gas liquids
WTI	West Texas Intermediate
CGU	cash-generating unit

Non–IFRS Measures

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

(a) **Adjusted Operating Field Netback -** Tamarack’s method of calculating adjusted operating field netback may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted operating field netback is calculated by taking net income or loss before taxes and adding back items, including transaction costs, and certain non-cash items including stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; impairment; unrealized gain or loss on financial instruments; and gain or loss on dispositions. Tamarack uses adjusted operating field netback as a key measure to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment. Adjusted operating field netback per share is calculated using the same weighted average basic and diluted shares used in calculating income (loss) per share. The calculation of the Company’s adjusted operating field netbacks are summarized starting on page 12 in the section titled “Adjusted Operating Field Netback and Net Income (Loss)”.

(b) **Operating Netback and Operating Field netback** - Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. These benchmarks do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties and net production and transportation costs. Operating field netback equals total petroleum and natural gas sales, less royalties and net production and transportation costs. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company’s netbacks can be seen starting on page 8 in the section titled “Operating Netback”.

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

The following outlines the Company's calculation of net debt (excluding the effect of derivative contracts):

($ thousand)	December 31, 2018	December 31, 2017
Accounts payable and accrued liabilities	$41,966	$51,059
Accounts receivable	(21,211)	(38,673)
Prepaid expenses and deposits	(2,370)	(3,095)
Working capital deficiency	18,385	9,291
Bank debt	161,495	163,889
Net debt	$179,880	$173,180

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

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

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

Selected Quarterly Information

Three months ended	**Dec. 31, 2018**	Sep. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017
Sales volumes								
Natural gas *(mcf/d)*	**50,262**	49,943	52,376	51,879	51,956	49,987	47,696	45,852
Oil and NGL *(bbls/d)*	**16,403**	16,441	15,124	14,885	14,148	12,210	11,387	10,154
Average boe/d *(6:1)*	**24,780**	24,765	23,853	23,532	22,807	20,541	19,336	17,796
Product prices								
Natural gas *($/mcf)*	**3.70**	1.63	1.65	2.25	1.89	1.62	3.01	2.89
Oil and NGL *($/bbl)*	**37.08**	73.81	72.66	65.86	62.34	50.29	51.77	55.74
Oil equivalent *($/boe)*	**32.05**	52.29	49.69	46.62	42.97	33.83	37.91	39.25
(000s, except per share amounts)								
Financial results								
Gross revenues	**73,075**	119,134	107,859	98,736	90,160	63,927	66,715	62,870
Cash provided by operating activities	**49,137**	62,644	64,606	60,285	50,056	35,237	34,537	24,695
Adjusted operating field netback (1)	**38,346**	68,579	61,005	58,545	57,583	34,774	33,670	32,356
Per share – basic	**0.17**	0.30	0.27	0.26	0.25	0.15	0.15	0.15
Per share – diluted	**0.17**	0.29	0.26	0.25	0.25	0.15	0.15	0.15
Net income (loss)	**18,952**	13,004	3,060	3,294	(12,525)	(6,742)	3,053	2,290
Per share – basic	**0.08**	0.06	0.01	0.01	(0.05)	(0.03)	0.01	0.01
Per share – diluted	**0.08**	0.06	0.01	0.01	(0.05)	(0.03)	0.01	0.01
Capital expenditures	**25,798**	78,149	52,674	69,630	35,516	74,063	19,002	63,721
Net acquisitions (dispositions)	**(4,823)**	–	(5,009)	2,790	1,713	2,962	1,301	75,995
Total assets	**1,264,053**	1,291,058	1,237,571	1,240,335	1,207,809	1,206,886	1,178,404	1,186,285
Net debt(1)	**179,880**	192,184	181,341	186,732	173,180	194,917	152,354	165,561
Bank debt	**161,495**	168,970	156,965	165,750	163,889	162,164	140,795	135,484
Decommissioning obligations	**193,003**	192,409	185,038	182,216	177,793	167,102	171,909	164,012

(1) Refer to definition of adjusted operating field netback and net debt under "Non-IFRS Measures".

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities, adjusted operating field netbacks and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange rates which can cause significant fluctuations in earnings due to unrealized

gains and losses recognized on a quarterly basis.

- On January 11, 2017, Tamarack closed the Viking Acquisition; in 2017 this acquisition added $62.3 million to oil and natural gas revenue and contributed $1.1 million to net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition.
- The Company recorded a net impairment charge on its Cardium oil cash-generating unit ("CGU") that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to falling gas prices in the amount of $58.0 million in Q4 2018 and an impairment reversal of $53.0 million on its Viking oil CGU. The Company recorded impairment charges on its heavy oil and certain natural gas related CGU due to falling oil and gas prices in the amount of $17.0 million in Q4 2017.

Selected Annual Information

Years ended December 31,	**2018**	2017	2016
Sales volumes			
Natural gas *(mcf/d)*	**51,108**	48,893	28,388
Oil and NGL *(bbls/d)*	**15,719**	11,987	5,613
Average boe/d *(6:1)*	**24,237**	20,136	10,344
Product prices			
Natural gas *($/mcf)*	**2.30**	2.32	2.41
Oil and NGL *($/bbl)*	**62.02**	55.36	44.06
Oil equivalent *($/boe)*	**45.08**	38.60	30.51
(000s, except per share amounts)			
Financial Results			
Gross revenues	**398,804**	283,672	115,517
Net income (loss)	**38,310**	(13,924)	(27,823)
Per share – basic	**0.17**	(0.06)	(0.23)
Per share – diluted	**0.16**	(0.06)	(0.23)
Capital expenditures	**226,251**	192,302	56,819
Net acquisitions (dispositions)	**(7,042)**	81,971	82,862
Total assets	**1,264,053**	1,207,809	663,564
Net debt(1)	**179,880**	173,180	52,316
Bank debt	**161,495**	163,889	45,227

(1) Refer to definition of net debt under "Non-IFRS Measures".

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On January 11, 2017, Tamarack closed the Viking Acquisition which added assets in Southeast

Alberta and Southwest Saskatchewan; in 2017 this acquisition added $62.3 million to oil and natural gas revenue and contributed $1.1 million to net loss.

- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions; in 2016 these acquisitions added $15.4 million to oil and natural gas revenue and contributed $0.1 million to the net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and recorded $0.6 million in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions.
- The Company recorded a net impairment charge on its Cardium oil CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to falling gas prices in the amount of $58.0 million in Q4 2018 and an impairment reversal of $53.0 million on its Viking oil CGU. The Company recorded impairment charges on its heavy oil and certain natural gas related CGUs due to falling oil and gas prices in the amount of $17.0 million in 2017 and $0.7 million of exploration and evaluation asset impairment in 2016.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

(a) **Oil and natural gas reserves** – Proved reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(b) **Exploration and evaluation assets ("E&E") –** The costs of drilling exploratory wells are initially capitalized as E&E assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and/or probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, estimated production costs and capital expenditures.

E&E expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, aggregated at the segment level.

(c) **Carrying value of property, plant and equipment ("PP&E")** – PP&E is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of PP&E and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as E&E assets or development and production assets within PP&E. E&E assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. The allocation of the Company's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for the Company's products and the way in which management monitors operations.

The Company assesses PP&E for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, the Company performs an impairment test related to the specific CGU. The determination of the recoverable amount of a CGU requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs could impact the fair value.

(d) **Decommissioning obligations –** The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk-free rate. The costs are included in PP&E and amortized over the useful life of the asset. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

(e) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(f) **Business combinations –** Management's judgment is required to determine whether a transaction constitutes a business combination or asset acquisition as determined based on the criteria in IFRS 3, "Business Combinations". Business combinations are differentiated from an asset acquisition when business processes are associated with the assets.

Business combinations within the scope of IFRS 3 are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Deferred taxes are recognized for any differences between the fair value and the tax basis of net assets acquired. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill.

Future Accounting Pronouncements

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported earnings or net assets of the Company.

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 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 has developed a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements. The Company is currently completing its review and analysis of the significant lease contracts that fall into the scope of the new 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.

Changes in Accounting Policies

Adoption of IFRS 15 “Revenue from Contracts with Customers”

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.

Adoption of IFRS 9 “Financial Instruments”

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 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.

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

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and bank debt continue to be measured at amortized cost and are now classified as “amortized cost”. There were no changes to Tamarack’s classification of its financial instrument derivative assets and liabilities as FVTPL.

The Company currently has no intentions of designating any of its financial instruments as hedges, nor does the Company currently apply hedge accounting.

Disclosure Controls and Internal Controls over Financial Reporting

The Company has designed disclosure controls and procedures (“DCP”) to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company’s ICFR.

No material changes in the Company’s DCP and its ICFR were identified during the period ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting. As a result, the Company’s DCP and its ICFR were effective as at December 31, 2018.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecast. Most of these risks (financial, operational or regulatory) are not within the Company’s control. While the following sections discuss some of these risks, they should not be construed as exhaustive. For a more fulsome risk discussion, refer to Tamarack’s AIF, which can be found on SEDAR at www.sedar.com.

Financial Risks

Financial risks include commodity pricing, exchange and interest rates and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company’s control and can significantly affect the Company’s financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. Due to both of these factors, Tamarack may enter into derivative instruments to partially mitigate the effects of downward price and foreign exchange volatility. To evaluate the need for hedging, management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects, the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completions technology.

Insurance is in place to protect against major asset destruction or business interruptions, and includes, but is not limited to events such as well blow-outs or pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the prevailing cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack employees address the continued development of a new or established reservoir on a go-forward basis, using the same procedure that is used to address exploration risk. The decision to produce reserves is made based on the amount of capital required, production practices and reservoir quality. Tamarack evaluates reservoir development based on the timing, amount of additional capital required and the expected change in production values. Finding and development costs are controlled when capital is employed in a cost-effective manner.

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. Restrictive new legislation is a risk the Company cannot control.

Forward-Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable Canadian securities legislation. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "budget", "plan", "endeavour", "continue", "estimate", "evaluate", "expect", "forecast", "monitor", "may", "will", "can", "able", "potential", "target", "intend", "consider", "focus", "identify", "use", "utilize", "manage", "maintain", "remain", "result", "cultivate", "could", "should", "believe" and similar expressions. The Company believes that the expectations reflected in such forward-looking statements are reasonable, but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

Without limitation, this MD&A contains forward-looking statements pertaining to:

- the intentions of management and the Company;
- continued issues related to commodity price differentials, market oversupply and Canadian infrastructure restrictions and the impact of the Government of Alberta's production curtailments and production management from the producer community thereon;
- the availability, size, terms, use and renewal of the Facility;

- estimated production rates in 2019, including in respect of the Cardium, Viking and Penny oil wells;
- the performance of the Viking waterflood project, including oil recoveries and corporate decline rates;
- future net production and transportation expenses and operating costs;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and by using financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack's intent to maintain balance sheet flexibility to allow the Company to take advantage of opportunities within the core areas, whether by increasing drilling activity or by completing tuck-in acquisitions;
- Tamarack's primary focus areas for production growth;
- future drilling plans;
- the impact of the Viking Pipeline Project on operating costs, transportation and the development of the Veteran Viking oil play;
- the capital cost payout of wells and Tamarack's strategy of focusing on drilling wells that target a certain return on capital cost payout and Tamarack's ability to control cost or reduce capital, production and transportation costs;
- deferred tax liabilities;
- expectations as to royalty rates as a percentage of revenue;
- future capital expenditures and capital program funding;
- future investment in pipeline infrastructure;
- contractual obligations and commitments;
- the estimates used to calculate the decommissioning obligations and depletion of PP&E;
- the Company's capital budget program and guidance 2019 and the weighting of activity levels between the first and second halves of 2019;
- share buy-backs for cancellation under the NCIB and RSU settlements;
- Tamarack's ability to explore alternative gas markets and diversify its gas price exposure;
- Tamarack's plan to accelerate or reduce capital expenditures, redirect capital to purchase shares or pay down debt if commodity prices significantly fluctuate from the 2019 price assumptions;
- expectations for oil, NGL and natural gas pricing in 2019 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2019.

With respect to the forward-looking statements contained in this MD&A, Tamarack has made assumptions regarding, among other things:

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production and transportation expenses and operating costs;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;

- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions and the Viking Acquisition and the related drilling programs;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax, royalty and regulatory regime.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the material uncertainties and risks described under the headings "Unit Cost Calculation", "Non-IFRS Measures", "Critical Accounting Estimates", "Future Accounting Pronouncements", "Changes in Accounting Policies", "Disclosure Controls and Internal Controls Over Financial Reporting", "Business Risks", "Financial Risks", "Operational Risks" and "Regulatory Risks";
- the material assumptions and observations described under the headings "Production", "Petroleum and Natural Gas Sales", "Royalties", "Net Production and Transportation Expenses", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expenses", "Interest Expense", "Depletion, Depreciation, Amortization and Accretion ("DDA&A")", "Income Taxes", "Adjusted Operating Field Netback and Net Income (Loss)", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Property Acquisitions and Dispositions", "Impairment", "Share Capital", "Liquidity and Capital Resources", "Bank Debt", "Guidance", "Commitments", "Selected Quarterly Information" and "Selected Annual Information";
- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to market for production;

- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production and transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2018, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at **www.tamarackvalley.ca**.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, capital expenditures, debt, net debt, cash flow, adjusted operating field netback, operating netback, net debt to annualized adjusted operating field netback ratio, capital cost payout, production and transportation expenses and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non-IFRS Measures".

The forward-looking statements and FOFI contained in this MD&A are made as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements, forward-looking information or FOFI whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements and FOFI contained herein are expressly qualified by this cautionary statement.

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

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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)	*(signed)*
Floyd Price	John Leach
Director	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.

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

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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