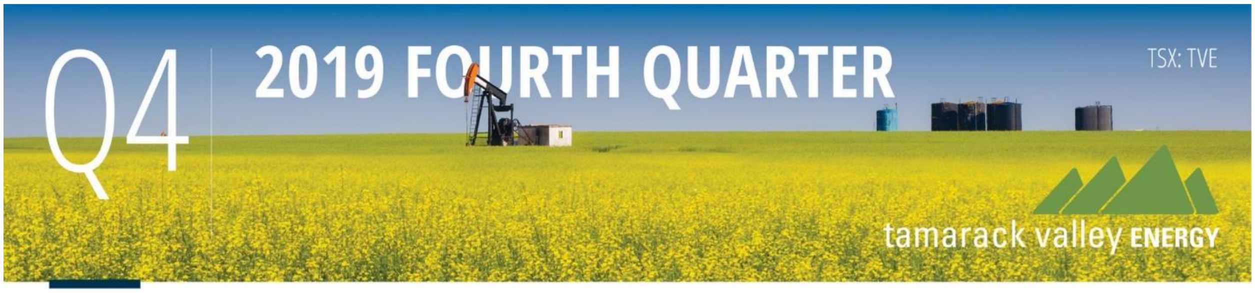

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

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 three months and years ended December 31, 2019 and 2018. This MD&A is dated and based on information available as at March 4, 2020 and should be read in conjunction with the audited consolidated financial statements ("financial statements") and the notes thereto for the years ended December 31, 2019 and 2018. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2019, 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 21. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q4 and Year End 2019 Financial and Operating Highlights

- Achieved stable quarterly production volumes of 24,859 boe/d in Q4/19, slightly higher than the Q4/18 average of 24,780 boe/d and 3% higher than the previous quarter, and annual volumes of 24,072 boe/d, while generating free adjusted funds flow (see "Non-IFRS Measures") of $40.5 million in 2019.
- Generated adjusted funds flow (previously referred to as "adjusted operating field netback"; see "Non-IFRS Measures") of $219.4 million in 2019 ($0.97 per share basic and diluted), compared to $226.5 million in 2018 ($0.99 per share basic and $0.97 per share diluted). Q4/19 adjusted funds flow was $54.7 million, an increase of $16.4 million, or 43%, over the same period in 2018.
- Invested $179.0 million in capital expenditures, excluding acquisitions, during 2019 which contributed to the drilling of 149 (144.5 net) wells, comprised of 127 (124.1 net) Viking oil wells, 14 (12.5 net) Cardium oil wells, two (2.0 net) Penny Barons oil wells and six (5.9 net) water source and injector wells, as well as bringing wells drilled in Q4/18 onto production in 2019.
- Directed free adjusted funds flow to key projects such as tuck-in acquisitions and the Company's active share repurchase program which included: $8.3 million to purchase and cancel 4.2 million shares; and, $3.5 million to purchase an additional 1.6 million shares to be held in trust by Tamarack's trustee for future restricted share units ("RSUs") settlement, offsetting RSU dilution and supporting debt-adjusted per share metrics.

- Reduced net debt by 11% quarter-over-quarter to $189.5 million, including working capital deficiency but excluding the fair value of financial instruments and lease liabilities, resulting in a 2019 net debt to annualized adjusted funds flow ratio (see “Non-IFRS Measures”) of 0.9 times.
- Held Tamarack’s oil and natural gas liquids (“NGL”) weighting stable at 63% year-over-year, while spending $30.3 million less in capital, after acquisitions and dispositions, with an 8% increase in incremental oil production over Q3 incremental and increasing waterflood production.
- Generated higher operating netbacks (see “Non-IFRS Measures”) in Q4/19 relative to Q4/18 and Q3/19 due in part to Tamarack’s ongoing focus on cost controls, while slightly lower annual operating netbacks in 2019 compared to 2018 reflects the impact of lower natural gas prices, offset by reductions in net production and transportation expenses stemming primarily from increased production from the lower-cost Veteran area.

Production

Quarter-over-Quarter

	Q4 2019	Q3 2019	% change
Production			
Light oil (bbls/d)	**13,729**	12,748	8
Heavy oil (bbls/d)	**318**	440	(28)
Natural gas liquids (bbls/d)	**1,735**	1,779	(2)
Natural gas (mcf/d)	**54,462**	55,224	(1)
Total (boe/d)	**24,859**	24,171	3
Percentage of oil and NGL	**63%**	62%	2

Average production for Q4/19 increased 3% from the previous quarter as a result of 11 net Viking oil wells coming on-stream that were drilled and awaiting completion at the end of Q3/19, plus 15 gross (14.6 net) Viking oil wells that were drilled and came on-stream in Q4/19. Rather than shut-in wells to comply with the Curtailment Order, Tamarack adjusted the timing of drilling and completion activity during 2019 and relied on the expected base production declines to remain below the imposed production limits. On August 20, 2019, the Government of Alberta announced that the Curtailment Order would extend to December 31, 2020, with possible early termination, and that the base limit for curtailment would increase from 10,000 to 20,000 bbls/d effective October 1, 2019 (the “Curtailment Limit Increase”). Due to the Curtailment Limit Increase, Tamarack ceased to be subject to the Curtailment Order commencing in October of 2019, and continues to be exempt from the Curtailment Order based on its current Alberta production levels of approximately 13,000 bbls/d. During the fourth quarter, the Company’s drilling program added 2,068 boe/d in Veteran (80% oil and NGL weighting).

In Q4/19, the Company’s average oil and NGL weighting increased to 63% compared to 62% in Q3/19.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2019	2018	% change	**2019**	2018	% change
Production						
Light oil (bbls/d)	**13,729**	14,163	(3)	**13,103**	13,769	(5)
Heavy oil (bbls/d)	**318**	755	(58)	**440**	552	(20)
Natural gas liquids (bbls/d)	**1,735**	1,485	17	**1,622**	1,398	16
Natural gas (mcf/d)	**54,462**	50,262	8	**53,444**	51,108	5
Total (boe/d)	**24,859**	24,780	–	**24,072**	24,237	(1)
Percentage of oil and NGL	**63%**	66%	(5)	**63%**	65%	(3)

Average production for Q4/19 and the year ended 2019 was similar to the same periods in 2018. The Company's oil and NGL weighting was lower for Q4/19 and the year ended 2019 relative to the same periods in 2018 due to the Company adjusting the timing of its capital investment and activity in order to comply with the Curtailment Order.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q4 2019	Q3 2019	% change
Revenue ($ thousands)			
Oil and NGL	**$86,398**	$81,771	6
Natural gas	**11,301**	7,808	45
Total	**$97,699**	$89,579	9
Average realized price:			
Light oil ($/bbl)	**64.26**	65.10	(1)
Heavy oil ($/bbl)	**58.96**	56.74	4
Natural gas liquids ($/bbl)	**21.96**	19.08	15
Combined average oil and NGL ($/boe)	**59.51**	59.38	–
Natural gas ($/mcf)	**2.26**	1.54	47
Revenue ($/boe)	**42.72**	40.28	6
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**56.91**	56.39	1
Edmonton Par (Cdn$/bbl)	**66.86**	69.18	(3)
Hardisty Heavy (Cdn$/bbl)	**50.06**	57.99	(14)
NYMEX monthly settlement (US$/mmbtu)	**2.62**	2.23	17
AECO daily index (Cdn$/mcf)	**2.46**	0.91	170
AECO monthly index (Cdn$/mcf)	**2.32**	1.04	123

Revenue from oil, natural gas and NGL sales in Q4/19 was 6% higher per boe than in Q3/19 primarily due to improved pricing. In response to a continued lack of pipeline takeaway capacity in Canada, the Curtailment Order was implemented in late 2018. The associated production curtailments, combined with active production management and engagement from the producer community, resulted in a significant narrowing of the WTI/Edmonton Par differential through 2019.

Although WTI increased steadily from its lows at the beginning of Q4/19, crude markets on average were relatively flat from Q3/19 to Q4/19, increasing only 1% to average US $56.91/bbl compared to US $56.39/bbl in the prior quarter. The WTI/Edmonton Par light oil differential widened through Q4/19, averaging US $5.39/bbl compared to US $4.68/bbl in Q3/19. This widening, in combination with the strengthening Canadian dollar relative to the US dollar, resulted in a 3% reduction in the average Edmonton Par price of $66.86/bbl in Q4/19 compared to Cdn $69.18/bbl in Q3/19. Tamarack's realized light oil wellhead price for the three months ended December 31, 2019 decreased 1% to $64.26/bbl from $65.10/bbl in the previous quarter, slightly ahead of the benchmark for the same period.

Although the light sweet differential has largely stabilized, Tamarack believes potential differential widening and volatility poses a continued risk to Canadian crude prices through 2020. The Government of Alberta has indicated that the Curtailment Order could remain in place until December 31, 2020; however, its future direction is uncertain and any changes to the current regulations could result in a material change to prices as a whole. In addition, negative sentiment due to an uncertain prognosis for additional pipeline capacity out of Western Canada presents further pricing risk. Tamarack has differential hedges protecting approximately 50% of forecasted oil production in 2020. Pricing is also highly susceptible to global macroeconomic events, as demonstrated by the recent volatility in the oil markets, with oil prices dropping dramatically subsequent to year end. While the timing, duration and magnitude of extreme oil price conditions are difficult to predict, Tamarack is committed to conservative planning and continues to explore strategies to mitigate and manage market risk through financial and physical hedges as well as alternate market delivery and pricing options.

Realized NGL prices increased 15% to $21.96/bbl in Q4/19 from $19.08/bbl in Q3/19. The increase is due to a combination of factors including increased WTI pricing in the quarter, which is the basis for condensate and butane pricing, as well as improved condensate differentials and stronger propane pricing through the later part of the quarter. While depressed butane pricing and increased fractionation fees for the 2019 to 2020 contract season have significantly reduced realized prices year-over-year, the market improvements did generate some quarter-over-quarter gains. Similar to other commodities, NGL supply has overwhelmed demand in the Alberta market and prices have been impacted by a lack of pipeline egress in Canada. However, Tamarack anticipates some minor improvements in NGL pricing due to market recoveries for the next contract year, which begins April 1, 2020.

Tamarack's realized natural gas price increased 47% to $2.26/mcf in Q4/19 from $1.54/mcf in Q3/19. The AECO daily benchmark price increased 170% to $2.46/mcf in Q4/19 from $0.91/mcf in Q3/19 and the NYMEX monthly settlement price increased 17% to US $2.62/mmbtu in Q4/19 from US $2.23/mmbtu in Q3/19. The increase in the Company's Q4/19 realized price compared to the previous quarter is due to expected increases in seasonal demand as well as near-term price increases in the Alberta market due to regulatory changes. Tamarack's value increase deviates from the increases seen in the two indices due to the Company's diversification strategy that balances its pricing exposure over multiple markets. While this diversification helps manage volatility and mitigates losses due to sudden downward changes in the market, it can prevent Tamarack from fully capitalizing on short term market gains. Despite a lower realized price in the quarter versus the benchmark, the full year effect of the Company's strategy had a positive financial impact. Tamarack's exposure to diversified gas markets is expected to continue providing meaningful benefit through both risk mitigation and improvements in realized pricing over the long-term.

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

Natural Gas Market	**Percentage Exposure (as at December 31, 2019)**
NYMEX (Physical Basis Swap)	27.2
AECO Daily (5A)	18.8
Waddington	18.0
Malin	14.4
Dawn	7.2
Chicago	7.2
Michigan City Gate	7.2
Fixed Price	0.0
AECO Daily (5A) + premium (SK)	0.0
	100%

Oversupply and takeaway capacity restrictions have continued to create downward pricing pressure and volatility in Alberta natural gas markets. Despite some improvement and stabilization in AECO prices as a result of recently approved regulatory changes, Tamarack anticipates challenging market conditions will persist for the long term. The Company continues to benefit from multiple third-party gas sales contracts featuring various end dates until 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate individual market volatility risk. Through the fourth quarter of 2019, more than 80% of Tamarack's total natural gas production was priced at alternate markets to AECO, including Malin, Chicago, Michigan Consolidated, Dawn, Waddington, Emerson and NYMEX. Pricing in these markets is contracted as daily index pricing less transportation tolls or as 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,		
	2019	2018	% change	**2019**	2018	% change
Revenue ($ thousands)						
Oil and NGL	**$86,398**	$55,962	54	**$340,835**	$355,826	(4)
Natural gas	**11,301**	17,113	(34)	**40,231**	42,978	(6)
Total	**$97,699**	$73,075	34	**$381,066**	$398,804	(4)
Average realized price:						
Light oil ($/bbl)	**64.26**	36.78	75	**66.25**	64.17	3
Heavy oil ($/bbl)	**58.96**	49.33	20	**55.27**	59.13	(7)
Natural gas liquids ($/bbl)	**21.96**	33.72	(35)	**25.57**	41.89	(39)
Combined average oil and NGL ($/boe)	**59.51**	37.08	60	**61.58**	62.02	(1)
Natural gas ($/mcf)	**2.26**	3.70	(39)	**2.06**	2.30	(10)
Revenue ($/boe)	**42.72**	32.05	33	**43.37**	45.08	(4)
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**56.91**	58.79	(3)	**57.02**	64.78	(12)
Edmonton Par (Cdn$/bbl)	**66.86**	48.26	39	**69.76**	69.14	1
Hardisty Heavy (Cdn$/bbl)	**50.06**	34.23	46	**60.13**	49.95	20
NYMEX monthly settlement (US$/mmbtu)	**2.62**	3.83	(32)	**2.78**	3.24	(14)
AECO daily index (Cdn$/mcf)	**2.46**	1.55	59	**1.51**	1.49	1
AECO monthly index (Cdn$/mcf)	**2.32**	1.89	23	**1.37**	1.52	(10)

Revenue per boe from oil, natural gas and NGL sales for Q4 2019 increased by 34% compared to the same period in 2018, primarily due to the increase in crude oil prices, partially offset by lower NGL and natural gas prices compared to the same period of the prior year.

For the year ended December 31, 2019 revenue per boe from oil, natural gas and NGL sales decreased by 4% compared to the same period in 2018, primarily due to the decrease in NGL and natural gas 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, 2019, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	4,000 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $60.78
Crude oil	2,700 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US $58.27
Crude oil	7,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US ($7.54)
Foreign exchange	1,000,000 US$/mth	January 1, 2020 – March 31, 2020	Exchange rate	Cdn $1.3405
Interest rate	25,000,000 US$/mth	January 1, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US$/mth	January 1, 2020 – June 14, 2023	Fixed rate	1.75%

At December 31, 2019, the commodity, foreign exchange and interest rate contracts were fair valued with a liability of $4.1 million (December 31, 2018 - $19.7 million asset) recorded on the balance sheet and an unrealized loss of $23.7 million recorded in earnings for the year ended December 31, 2019 (December 31, 2018 - $27.1 million unrealized gain).

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, 2019, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	7,901 GJ/day	January 1, 2020 – January 31, 2020	AECO fixed price	Cdn $2.64
Natural gas	2,320 GJ/day	February 1, 2020 – February 29, 2020	AECO fixed price	Cdn $2.30
Natural gas	15,000 mmbtu/day	February 1, 2020 – February 29, 2020	AECO/Henry Hub differential	Index – US $0.56
Natural gas	5,000 GJ/day	March 1, 2020 – March 31, 2020	AECO fixed price	Cdn $2.45
Natural gas	15,000 mmbtu/day	March 1, 2020 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.16
Natural gas	15,000 mmbtu/day	April 1, 2020 – October 31, 2020	AECO/Henry Hub differential	Index – US $1.23

Since December 31, 2019, the Company adjusted its derivative portfolio by entering into a transaction that cancelled a portion of existing derivative contracts and re-entered into new derivative contracts. As at March 4, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Quantity	Term	Hedge type	Strike price
Crude oil	1,000 bbls/day	March 4, 2020 – March 31, 2020	WTI fixed price	US $59.86
Crude oil	500 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US $59.17
Crude oil	3,000 bbls/day	July 1, 2020 – September 30, 2020	WTI fixed price	US $54.57
Crude oil	3,000 bbls/day	October 1, 2020 – December 31, 2020	WTI fixed price *	US $54.57
Crude oil	5,650 bbls/day	March 4, 2020 – March 31, 2020	WTI Put	US $58.00
Crude oil	4,400 bbls/day	April 1, 2020 – June 30, 2020	WTI Put	US $58.00
Crude oil	1,700 bbls/day	July 1, 2020 – September 30, 2020	WTI Put	US $58.00
Crude oil	7,000 bbls/day	March 4, 2020 – December 31, 2020	WTI/Edm par differential	US ($7.54)
Foreign exchange	1,000,000 US$/mth	March 4, 2020 – March 31, 2020	Exchange rate	Cdn $1.3405
Foreign exchange	3,000,000 US$/mth	April 1, 2020 – June 30, 2020	Exchange rate	Cdn $1.3271
Interest rate	25,000,000 US$/mth	March 4, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US$/mth	March 4, 2020 – June 14, 2023	Fixed rate	1.75%

* Extendable for an additional six months at the counter-parties discretion.

Since December 31, 2019, the Company has not entered into any additional physical contracts.

Royalties

Quarter-over-Quarter

	Q4 2019	Q3 2019	% change
Royalty expenses ($ thousands)	**$10,041**	$9,691	4
$/boe	**4.39**	4.36	1
percent of sales	**10**	11	(9)

Royalties as a percentage of revenue were comparable in Q4/19 relative to Q3/19.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2019	2018	% change	**2019**	2018	% change
Royalty expenses ($ thousands)	**$10,041**	$5,902	70	**$39,060**	$39,901	(2)
$/boe	**4.39**	2.59	69	**4.45**	4.51	(1)
percent of sales	**10**	8	25	**10**	10	–

Royalties as a percentage of revenue for the three months ended December 31, 2019 were higher than the same period in 2018, which was due to the sliding scale nature of some oil royalties which lowers the percentage paid during periods of low oil prices, which was the case during Q4/18. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for 2020 based on current forecast commodity price levels.

Royalties as a percentage of revenue for the year ended December 31, 2019 were comparable to the same period in 2018.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2019**	Q3 2019	% change
Production and transportation expenses	**$23,212**	$22,901	1
Less: processing income	**431**	963	(55)
Total net production and transportation expenses	**$22,781**	$21,938	4
Total ($/boe)	**$9.96**	$9.87	1

Net production and transportation expenses in Q4/19 were 1% higher at $9.96/boe compared to $9.87/boe in Q3/19, primarily due to start-up costs for the new wells brought on-stream during the quarter, which led to higher net production and transportation expenses per boe.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2019**	2018 [(1)]	% change	**2019**	2018 [(1)]	% change
Production and transportation expenses	**$23,212**	$24,291	(4)	**$89,897**	$93,683	(4)
Less: processing income	**431**	426	1	**1,750**	658	166
Total net production and transportation expenses	**$22,781**	$23,865	(5)	**$88,147**	$93,025	(5)
Total ($/boe)	**$9.96**	$10.47	(5)	**$10.03**	$10.52	(5)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months and year ended December 31, 2019, net production and transportation expenses per boe were lower compared to the same periods in 2018. This resulted from several factors, including the net impact of reduced transportation costs in the Veteran area as a result of a commissioned oil sales pipeline which eliminated the trucking of sales oil in late Q4/18, the Company adopting IFRS 16, *"Leases"* ("IFRS 16") in 2019 and an increase in production volumes in the Veteran area, where production expenses are generally lower than the corporate average.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q4 2019**	Q3 2019	% change
Average realized sales	**$42.72**	$40.28	6
Royalty expenses	**(4.39)**	(4.36)	1
Net production and transportation expenses	**(9.96)**	(9.87)	1
Operating field netback	**28.37**	26.05	9
Realized commodity hedging loss	**(2.04)**	(1.55)	32
Operating netback	**$26.33**	$24.50	7

The Company's operating netback (see "Non-IFRS Measures") increased 7% in Q4/19 compared to Q3/19. This was primarily due to a higher realized price for natural gas compared to the previous quarter.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2019**	2018 [1]	% change	**2019**	2018 [1]	% change
Average realized sales	**$42.72**	$32.05	33	**$43.37**	$45.08	(4)
Royalty expenses	**(4.39)**	(2.59)	69	**(4.45)**	(4.51)	(1)
Net production and transportation expenses	**(9.96)**	(10.47)	(5)	**(10.03)**	(10.52)	(5)
Operating field netback	**28.37**	18.99	49	**28.89**	30.05	(4)
Realized commodity hedging gain (loss)	**(2.04)**	0.04	(5,200)	**(1.42)**	(2.03)	(30)
Operating netback	**$26.33**	$19.03	38	**$27.47**	$28.02	(2)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months ended December 31, 2019, operating netbacks were higher than the same period in 2018 due to higher realized oil prices in 2019, partially offset by a realized hedging loss in 2019 and lower NGL and natural gas prices in Q4/19 relative to Q4/18.

For the year ended December 31, 2019, operating netbacks were lower than the same period in 2018 due to lower natural gas prices in 2019 partially offset by lower net production and transportation expense in 2019.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2019**	Q3 2019	% change
Gross costs	**$4,290**	$4,091	5
Capitalized costs and recoveries	**(992)**	(1,003)	(1)
General and administrative costs	**$3,298**	$3,088	7
Total ($/boe)	**$1.44**	$1.39	4

Gross and net G&A expenses for the fourth and third quarters of 2019 were comparable. 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)	**2019**	2018	% change	**2019**	2018	% change
Gross costs	**$4,290**	$4,272	–	**$16,306**	$17,064	(4)
Capitalized costs and recoveries	**(992)**	(934)	6	**(3,842)**	(3,678)	4
General and administrative costs	**$3,298**	$3,338	(1)	**$12,464**	$13,386	(7)
Total ($/boe)	**$1.44**	$1.46	(1)	**$1.42**	$1.51	(6)

Gross and net G&A costs decreased for the three months and year ended December 31, 2019, compared to the same periods in 2018, due to a continued focus on cutting non-essential G&A costs. On a per boe basis, net G&A costs for the three months and year ended December 31, 2019 were lower than the same periods in 2018 due to lower absolute gross and net G&A expenses.

Stock-Based Compensation Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2019**	Q3 2019	% change
Gross costs	**$3,594**	$3,616	(1)
Capitalized costs	**(612)**	(628)	(3)
Total stock-based compensation	**$2,982**	$2,988	–
Total ($/boe)	**$1.30**	$1.34	(3)

Stock-based compensation expense related to stock options ("Options"), restricted share units ("RSUs") and performance share units ("PSUs") was similar in Q4/19 compared to Q3/19. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2019**	2018	% change	**2019**	2018	% change
Gross costs	**$3,594**	$4,040	(11)	**$12,073**	$12,471	(3)
Capitalized costs	**(612)**	(1,140)	(46)	**(2,384)**	(3,598)	(34)
Total stock-based compensation	**$2,982**	$2,900	3	**$9,689**	$8,873	9
Total ($/boe)	**$1.30**	$1.27	2	**$1.10**	$1.00	10

Stock-based compensation expense related to Options, RSUs and PSUs for the three months and year ended December 31, 2019 was higher compared to the same periods in 2018 due to additional Options, RSUs and PSUs that were issued late in Q1/19. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

During the year ended December 31, 2019, the Company issued 0.4 million Options (at a weighted average exercise price of $2.57 per share), 2.5 million RSUs and 1.2 million PSUs compared to 0.2 million Options (at a weighted average exercise price of $2.62 per share), 2.4 million RSUs and 1.0 million PSUs during the same period in 2018.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2019**	Q3 2019	% change
Interest on bank debt	**$1,938**	$1,890	3
Fees associated with credit facility renewal	**8**	(13)	(162)
Interest on lease liabilities	**234**	243	(4)
Total interest expense	**$2,180**	$2,120	3
Total ($/boe)	**$0.95**	$0.95	–
Average drawings on bank debt	**$198,887**	$182,075	9

Interest expense was higher in Q4/19 compared to the previous quarter due to a higher average amount drawn quarter-over-quarter on the revolving credit facility.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2019**	2018 (1)	% change	**2019**	2018 (1)	% change
Interest on bank debt	**$1,938**	$1,706	14	**$7,573**	$7,681	(1)
Fees associated with credit facility renewal	**8**	–	–	**631**	391	61
Interest on lease liabilities	**234**	–	–	**1,241**	–	–
Total interest expense	**$2,180**	$1,706	28	**$9,445**	$8,072	17
Total ($/boe)	**$0.95**	$0.75	27	**$1.07**	$0.91	18
Average drawings on bank debt	**$198,887**	$159,286	25	**$187,575**	$158,898	18

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

Interest expense for the three months and year ended December 31, 2019 was higher than the same periods in 2018 due to the Company adopting IFRS 16 in 2019 and the higher average drawings on the revolving credit facility, offset by increased utilization of lower interest rate options that were available through the Company's syndicate of lenders.

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

The Company depletes its property, plant and equipment ("PP&E") based on its proved plus probable reserves. Right-of-use ("ROU") assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the underlying asset or the lease term. If the lease transfers ownership of the underlying asset to the Company at the end of the lease term, or the Company is reasonably certain it will exercise its purchase option, Tamarack depletes its ROU assets 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 2019**	Q3 2019	% change
Depletion and depreciation	**$43,172**	$42,483	2
Amortization of undeveloped leases	**266**	266	–
Accretion	**954**	950	–
Total	**$44,392**	$43,699	2
Depletion and depreciation ($/boe)	**$18.88**	$19.10	(1)
Amortization ($/boe)	**0.12**	0.12	–
Accretion ($/boe)	**0.42**	0.43	(2)
Total ($/boe)	**$19.42**	$19.65	(1)

DDA&A expense per boe and on an absolute basis for the fourth and third quarters of 2019 were comparable with a slight decrease in the DDA&A expense per boe. The decrease was due to the completion of the Company's December 31, 2019 independent reserves evaluation which resulted in an increase in Tamarack's overall reserve base.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2019**	2018 [1]	% change	**2019**	2018 [1]	% change
Depletion and depreciation	**$43,172**	$44,498	(3)	**$166,312**	$176,498	(6)
Amortization of undeveloped leases	**266**	328	(19)	**999**	1,078	(7)
Accretion	**954**	1,043	(9)	**4,075**	4,106	(1)
Total	**$44,392**	$45,869	(3)	**$171,386**	$181,682	(6)
Depletion and depreciation ($/boe)	**$18.88**	$19.52	(3)	**$18.93**	$19.95	(5)
Amortization ($/boe)	**0.12**	0.14	(14)	**0.11**	0.12	(8)
Accretion ($/boe)	**0.42**	0.46	(9)	**0.46**	0.46	–
Total ($/boe)	**$19.42**	$20.12	(3)	**$19.50**	$20.53	(5)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months and year ended December 31, 2019, DDA&A expense per boe was lower relative to the same periods in 2018. The decrease was due to the completion of the Company's December 31, 2019 independent reserves evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2019 drilling program, better-than-expected well performance, additional reserves being added as a result of the Veteran waterflood project and a net impairment taken in the fourth quarter of 2018. On an absolute basis, DDA&A expense was lower for both the three months and year ended December 31, 2019 due to the lower DDA&A expense per boe.

Impairment

Impairment of $68.0 million was recorded as at December 31, 2019 as a result of a decrease in current and forecast future natural gas and NGL prices. The impairment recognized relates to the Company's Cardium cash-generating unit ("CGU") that includes associated natural gas produced with the Cardium oil and also includes Mannville gas wells and a Pekisko gas unit. The recoverable amount of this CGU as at December 31, 2019 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 10% to 20% (level 3 inputs). The recoverable amount of the Cardium CGU was determined using the fair value less costs of disposal methodology. This methodology is based on what Tamarack could receive should these assets be disposed in the current environment taking into account lower natural gas and NGL prices.

Income Taxes

The Company did not incur any cash tax expense for the three months and year ended December 31, 2019 and does not expect to pay any cash tax until 2023 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

The Company has incorporated the Alberta corporate income tax rate reductions enacted by the Government of Alberta for the periods from July 1, 2019 to January 1, 2022, which reduced the provincial income tax rate to 11% effective July 1, 2019 and will further reduce the rate by an additional 1% on January 1 for each of the years 2020, 2021 and 2022, bringing the rate to 8%. The deferred income tax recovery includes $4.3 million attributable to these tax rate decreases.

For the three months and year ended December 31, 2019, a deferred income tax recovery of $11.5 million and $14.4 million were recognized, respectively, compared to a deferred income tax expense of $11.5 million and $20.8 million for the same periods in 2018.

The following table outlines the Company's estimated tax pools as at December 31, 2019:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	31
Canadian development expense (CDE)	30%	315
Canadian oil and gas property expense (COGPE)	10%	210
Non-capital losses (NCL)	100%	166
Undepreciated capital cost (UCC)	25%	136
Share issue costs and other	various	1
Total		859

Adjusted Funds Flow and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q4 2019**	Q3 2019	% change
Income (loss) before taxes	**$(62,028)**	$782	(8,032)
Depletion, depreciation and amortization	**43,438**	42,749	2
Stock-based compensation	**2,982**	2,988	–
Gain on disposition of property, plant and equipment	**(27)**	–	–
Accretion expense on decommissioning obligations	**954**	950	–
Unrealized loss on financial instruments	**1,374**	1,814	(24)
Unrealized gain on foreign exchange	**(2,859)**	–	–
Unrealized loss on cross-currency swaps	**2,908**	–	–
Impairment of property, plant and equipment	**68,000**	–	–
Adjusted funds flow	**$54,742**	$49,283	11
Per share - basic	**$0.25**	$0.22	14
Per share - diluted	**$0.25**	$0.22	14
Net loss	**$(50,546)**	$(111)	45,437
Per share - basic	**$(0.23)**	$(0.00)	–
Per share - diluted	**$(0.23)**	$(0.00)	–

The adjusted funds flow (see "Non-IFRS Measures") generated during Q4/19 was higher than in Q3/19 primarily due to a 6% increase in realized commodity prices.

The Company recorded a net loss of $50.5 million ($0.23 per share basic and diluted) during the three months ended December 31, 2019, compared to a net loss of $0.1 million ($0.00 per share basic and diluted) during the previous quarter. This was primarily due to an impairment to property, plant and equipment taken in Q4/19, partially offset by a 6% increase in realized commodity prices in Q4/19 and a deferred income tax recovery in Q4/19.

Year-over-Year

($ thousands, except per boe)	Three months ended December 31, 2019	2018 (1)	% change	Years ended December 31, 2019	2018 (1)	% change
Income (loss) before taxes	**$(62,028)**	$30,415	(304)	**$(53,409)**	$59,142	(190)
Depletion, depreciation and amortization	**43,438**	44,826	(3)	**167,311**	177,576	(6)
Stock-based compensation	**2,982**	2,900	3	**9,689**	8,873	9
Gain on disposition of property, plant and equipment	**(27)**	(1,079)	(97)	**(27)**	(1,085)	(98)
Accretion expense on decommissioning obligations	**954**	1,043	(9)	**4,075**	4,106	(1)
Unrealized loss (gain) on financial instruments	**1,374**	(44,759)	(103)	**23,746**	(27,137)	(188)
Unrealized gain on foreign exchange	**(2,859)**	–	–	**(2,859)**	–	–
Unrealized loss on cross-currency swaps	**2,908**	–	–	**2,908**	–	–
Impairment of property, plant and equipment	**68,000**	5,000	1,260	**68,000**	5,000	1,260
Adjusted funds flow	**$54,742**	$38,346	43	**$219,434**	$226,475	(3)
Per share - basic	**$0.25**	$0.17	47	**$0.97**	$0.99	(2)
Per share - diluted	**$0.25**	$0.17	47	**$0.97**	$0.97	–
Net income (loss)	**$(50,546)**	$18,952	(367)	**$(39,011)**	$38,310	(202)
Per share - basic	**$(0.23)**	$0.08	(388)	**$(0.17)**	$0.17	(200)
Per share - diluted	**$(0.23)**	$0.08	(388)	**$(0.17)**	$0.16	(206)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

The adjusted funds flow (see "Non-IFRS Measures") for the three months ended December 31, 2019 was higher compared to the same period of 2018. This was primarily due to a 33% increase in realized commodity prices in Q4/19.

The adjusted funds flow (see "Non-IFRS Measures") for the year ended December 31, 2019 was lower than in the same period of 2018. This was primarily due to a 4% decrease in realized commodity prices in 2019.

The Company recorded a net loss of $50.5 million ($0.23 per share basic and diluted) and $39.0 million ($0.17 per share basic and diluted), respectively, during the three months and year ended December 31, 2019, compared to 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) for the same periods in 2018.

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)	**2019**	2018	% change	**2019**	2018	% change
Land	**$1,090**	$42	2,495	**$1,603**	$4,690	(66)
Geological and geophysical	**74**	–	–	**198**	13	1,423
Drilling and completion	**16,251**	15,254	7	**129,344**	167,216	(23)
Equipment and facilities	**4,646**	9,664	(52)	**44,378**	51,254	(13)
Capitalized G&A	**807**	791	2	**3,033**	2,861	6
Office equipment	**86**	47	83	**410**	217	89
Total capital expenditures	**$22,954**	$25,798	(11)	**$178,966**	$226,251	(21)

During the fourth quarter of 2019, the Company drilled, completed and equipped 15 (14.6 net) Viking oil wells. In addition to the fourth quarter drilling program, the Company also completed and brought on production 11.0 net Viking oil wells that were drilled in late Q3/19.

Tamarack also directed capital to the continued development of a waterflood program in the Company's Veteran, Alberta area with the conversion of 6 (5.9 net) Viking oil wells into water injectors. The waterflood project is designed to improve oil recoveries, reduce corporate decline rates and increase production rates while utilizing Tamarack's existing and owned infrastructure. These supplementary projects are subject to the same rate of return thresholds as those used for development drilling when competing for capital.

For the year ended December 31, 2019 Drilling Summary		
	Gross	Net
Viking	127.0	124.1
Cardium	14.0	12.5
Penny	2.0	2.0
Water source and injectors	6.0	5.9
	149.0	144.5

As at December 31, 2019, the Company's net undeveloped land totaled 496,441 acres.

Property Acquisitions

During the year ended December 31, 2019, the Company completed a total of six tuck-in acquisitions for $9.9 million, adding 17.9 net sections of undeveloped Viking land adjacent to Tamarack's existing acreage in the Veteran/Consort area, 0.6 net sections in the Wilson Creek/Alder Flats area and approximately 800 boe/d of associated production.

Share Capital

At December 31, 2019, Tamarack had issued and outstanding 222,793,117 Common Shares ("Common Shares"), net of 469,120 Common Shares which were held in treasury, 2,193,333 Options, 6,986,921 RSUs and 2,156,980 PSUs. At March 4, 2020, Tamarack has issued and outstanding 222,295,253 Common Shares, of which 302,884 are held in treasury, 1,942,333 Options, 6,403,019 RSUs and 2,166,980 PSUs. This compares to December 31, 2018, at which time Tamarack had issued and outstanding 226,072,693 Common Shares, of which 1,193,188 were held in treasury, 2,944,833 Options, 7,407,472 RSUs and 983,000 PSUs. No preferred shares of Tamarack are issued and outstanding.

At December 31, 2019, Tamarack Acquisition Corp. had 1,021,974 preferred shares ("TAC Preferred Shares") issued and outstanding (December 31, 2018 - 1,086,974). The TAC Preferred Shares were fully vested and exchangeable into 982,667 Common Shares (December 31, 2018 - 1,045,168) of Tamarack at an exchange price of $3.12 per Common Share.

At March 4, 2020, Tamarack Acquisition Corp. had 740,307 preferred shares ("TAC Preferred Shares") issued and outstanding. The TAC Preferred Shares were fully vested and exchangeable into 711,834 Common Shares of Tamarack at an exchange price of $3.12 per Common Share.

As noted under "Liquidity and Capital Resources" below, during the year ended December 31, 2019, Tamarack purchased and cancelled 4,181,100 outstanding Common Shares under its normal course issuer bid ("NCIB") program, for a total investment of $8.3 million. This compared to the year ended December 31, 2018, when Tamarack purchased and cancelled 3,025,000 outstanding Common Shares under its NCIB program, for a total investment of $11.7 million. The NCIB program 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 program also helps to offset the dilutive impact that may be associated with the exercise and settlement of Options, RSUs and PSUs issued under Tamarack's stock-based compensation programs.

Liquidity and Capital Resources

($ thousands)	**December 31, 2019**	December 31, 2018 (1)	September 30, 2019
Working capital deficiency (surplus)	**$(3,426)**	$18,385	$14,169
Bank debt	**192,907**	161,495	198,971
Net debt	**189,481**	179,880	213,140
Quarterly adjusted funds flow	**$54,742**	$38,346	$49,283
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**218,968**	153,384	197,132
Net debt to annualized adjusted funds flow	**0.9x**	1.2x	1.1x

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency and the fair value of cross-currency swaps but excluding the fair value of financial instruments and lease liabilities, totaled $189.5 million as at December 31, 2019. This compares to its net debt of $213.1 million and $179.9 million in Q3/19 and Q4/18, respectively. Tamarack's Q4/19 net debt to annualized adjusted funds flow ratio (see "Non-IFRS Measures") was 0.9 times.

The Company's $23.2 million investment in capital expenditures and property acquisitions during Q4/19 was funded entirely by Tamarack's adjusted funds flow (see "Non-IFRS Measures") of $54.7 million. Tamarack net debt levels decreased $23.7 million during Q4/19 due to the planned reduction in capital expenditures.

With continued commodity price volatility, 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, enhancing production 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 program through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company has the option to purchase its Common Shares for cancellation, thereby reducing the total number of shares outstanding. The NCIB program represents an additional tool that can be employed as part of management's ongoing strategy to increase long-term shareholder value. For the year ended December 31, 2019, the Company spent $8.3 million to purchase and cancel 4,181,100 outstanding Common Shares under the NCIB program. Subsequent to the end of the year, the Company purchased an additional 664,100 outstanding Common Shares under the NCIB program for $1.3 million.

Over and above the NCIB program, during the fourth quarter of 2019, the Company also directed $1.1 million to purchase 592,199 issued and outstanding Common Shares in the open market. Once purchased, these Common Shares are held in trust by Tamarack's trustee and used to settle RSUs upon future exercises. This practice mitigates dilution by eliminating the need to issue new Common Shares from treasury for the settlement of RSUs and PSUs. Instead, Tamarack has the ability, when needed, to 'draw down' from the remaining balance of purchased Common Shares that are held in trust to settle RSU exercises, further supporting Tamarack's per share metrics. At December 31, 2019, the remaining balance of purchased Common Shares held in trust totaled 469,120.

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 $320 million and a $30 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility totals $350 million, of which $192.9 million was drawn as of December 31, 2019 (December 31, 2018 - $161.5 million), lasts for a 365-day period and will be subject to its next 365-day extension by May 31, 2020. If not extended on May 31, 2020, the Facility will cease to revolve and all outstanding balances will become repayable one year from that date.

The Facility includes an accordion feature which allows Tamarack to increase the revolving credit facility portion 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, 2019, the accordion feature had 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 that Tamarack employs will vary from time to time based on capital needs and current market rates. As at December 31, 2019, the

Facility was secured by a $1.0 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's 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 by the syndicate of lenders is scheduled to be completed by May 31, 2020.

There are no financial covenants governing the Facility.

Guidance

Tamarack's average annual production for 2019 of 24,072 boe/d was in line with guidance of 23,500 to 24,500 boe/d (oil and NGL weighting of 63% to 65%).

Over the past several years, Tamarack has maintained a disciplined capital allocation strategy designed to achieve sustainability through environments of weak and volatile oil prices, while continuing to direct excess adjusted funds flow to purchase its Common Shares under its normal course issuer bid ("NCIB") program. During the 12 months ended December 31, 2019, Tamarack invested $8.3 million to purchase and cancel 4,181,100 Common Shares. In addition, the Company further invested $3.5 million to purchase an additional 1,639,764 Common Shares to be held in trust by Tamarack's trustee and used to settle RSUs upon future exercises, offsetting future RSUs dilution and supporting debt-adjusted per share growth (see "Non-IFRS Measures").

Tamarack's 2020 budget of $170 to $180 million is forecast to drive average production volumes consistent with 2019 guidance levels, ranging from 23,500 to 24,500 boe/d, and is expected to be funded entirely by the Company's adjusted funds flow. The program is focused on increasing oil and liquids weightings at year end 2020. This positive impact is a direct result of slowing down the Company's corporate oil decline rate due to an increasing anticipated response from the waterflood development at Veteran, which will continue to enhance Tamarack's longer-term sustainability.

The 2020 capital budget of $170 to $180 million includes maintenance capital estimated to range between $112 and $115 million which is designed to keep production flat, while approximately $50 to $58 million has been earmarked for Viking waterflood development projects, anticipated to positively impact decline rates and production later in 2020 and into 2021. In addition, Tamarack plans to direct between $5 and $8 million to expenditures for land and seismic, approximately $3 million for abandonment projects, and $2 to $3 million in initiatives designed to reduce emissions as part of the Company's ongoing commitment to its environmental, social and governance responsibilities. Tamarack's 2020 capital program assumes a decrease in corporate declines from 38% in 2019 to 34% in 2020, with corporate declines expected to fall below 30% in 2021 as a result of the positive response from ongoing waterflood development.

Tamarack's 2020 maintenance capital budget anticipates the drilling of 90 to 100 net wells, including 80 to 90 Viking light oil wells, seven to nine Cardium light oil wells and two to five wells at Penny targeting the Lower Mississippian development. The Company's $50 to $58 million of planned waterflood investment in 2020 is expected to include 14 to 16 well conversions in 2020 and the drilling of 15 to 20 additional injection wells at East Veteran.

Tamarack's 2020 capital program will be fully funded by adjusted funds flow at current strip prices. Adjusted funds flow that are generated above capital expenditures will be directed 50% to the purchase of shares for cancelation through the NCIB program and to offset future RSU dilution, with the remaining 50% directed towards debt repayment or continued accretive tuck-in acquisitions.

The Company's 2020 budget is summarized in the following table:

	2020 Budget
Average annual production (boe/d)	23,500 – 24,500
Oil and NGL weighting (%)	~64 – 66
Exit production (boe/d)	23,500 – 24,500
Oil weighting (%)	~59 – 62
Oil and NGL weighting (%)	~65 – 68
2020 Capital expenditures, excluding acquisitions ($millions)	$170 – 180

This budget has been designed to optimize returns, allowing Tamarack to enhance per share metrics and fully fund its capital expenditure program. This budget reflects the continued volatility in equity markets, uncertainty of future oil pricing given backwardation of the forward curve, as well as the uncertain prognosis for additional pipeline takeaway capacity from western Canada. In light of management's belief that the Company's prevailing share price does not adequately reflect the underlying value of its assets, Tamarack intends to continue to purchase shares through its NCIB program even if commodity prices remain low.

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

Commitments

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases for facilities on the balance sheet. These liabilities were previously reported as commitments. The following table summarizes the Company's commitments as at December 31, 2019:

($ thousands)	2020	2021	2022	2023	2024	2025+
Bank debt	–	192,907	–	–	–	–
Office lease(1)	263	–	–	–	–	–
Take or pay commitments(2)	2,256	2,294	2,340	2,396	–	–
Gas transportation(3)	229	76	–	–	–	–
Total	2,748	195,277	2,340	2,396	–	–

(1) Relates to the operating costs for the office lease which are a non-lease component of lease liabilities.

(2) 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.

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

Rental fees, which were in the December 31, 2018 commitments table, were removed due to the adoption of IFRS 16. The amounts removed were as follows:

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Rental fee	6,312	6,312	6,312	4,441	2,570	1,142	1,285

Contingency

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of $56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of $1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged the Company has breached its fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in the consolidated financial statements.

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a boe using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion complies with 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
CGU	cash-generating unit
GJ	gigajoule
IFRS	International Financial Reporting Standards
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

Non–IFRS Measures

This document contains the terms "adjusted funds flow", "free adjusted funds flow", "operating netback", "operating field netback", "net debt", "netbacks", "capital cost payout", "net debt to annualized adjusted funds flow 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 funds flow -** Tamarack's method of calculating adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted funds flow is calculated by taking net income or loss before taxes and adding back items, including transaction costs, and certain non-cash items including stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; impairment;

unrealized gain or loss on financial instruments; unrealized gain or loss on foreign exchange; unrealized gain or loss on cross-currency swaps; and gain or loss on dispositions. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income (loss) per share. The calculation of the Company's adjusted funds flows is summarized starting on page 14 in the section titled "Adjusted funds flow and Net Income (Loss)".

(b) **Operating Netback and Operating Field netback** - Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. These benchmarks do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity, foreign exchange and interest rate 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 9 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 surplus or deficit, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

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

($ thousands)	December 31, 2019	December 31, 2018 [1]
Accounts payable and accrued liabilities	$37,809	$41,966
Cross-currency swap liability	2,908	–
Accounts receivable	(42,219)	(21,211)
Prepaid expenses and deposits	(1,924)	(2,370)
Working capital deficiency (surplus)	(3,426)	18,385
Bank debt	192,907	161,495
Net debt	$189,481	$179,880

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

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

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

(f) **Free Adjusted Funds Flow –** Management uses certain industry benchmarks, such as free adjusted funds flow, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions, Management believes that free adjusted funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

(g) **Debt-Adjusted Production per Share Growth** - Management uses certain measurements such 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 were 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 a higher magnitude of their growth is financed through debt rather 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 so that investors can appreciate the impact that debt on a company's balance sheet has on its per share growth disclosure. In addition, it demonstrates the strength of one company's balance sheet relative to an over-leveraged peer, particularly in volatile commodity price environments where indebtedness could increase as a result of lower cash flows and higher debt service costs.

Selected Quarterly Information

Three months ended	**Dec. 31, 2019**	Sep. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018 (2)	Sep. 30, 2018 (2)	Jun. 30, 2018 (2)	Mar. 31, 2018 (2)
Sales volumes								
Natural gas *(mcf/d)*	**54,462**	55,224	53,451	50,576	50,262	49,943	52,376	51,879
Oil and NGL *(bbls/d)*	**15,782**	14,967	15,181	14,720	16,403	16,441	15,124	14,885
Average boe/d *(6:1)*	**24,859**	24,171	24,090	23,149	24,780	24,765	23,853	23,532
Product prices								
Natural gas *($/mcf)*	**2.26**	1.54	1.71	2.82	3.70	1.63	1.65	2.25
Oil and NGL *($/bbl)*	**59.51**	59.38	65.46	62.07	37.08	73.81	72.66	65.86
Oil equivalent *($/boe)*	**42.72**	40.28	45.04	45.62	32.05	52.29	49.69	46.62
(000s, except per share amounts)								
Financial results								
Gross revenues	**97,699**	89,579	98,741	95,047	73,075	119,134	107,859	98,736
Cash provided by operating activities	**54,623**	42,199	60,320	48,089	49,137	62,644	64,606	60,285
Adjusted funds flow (1)	**54,742**	49,283	57,906	57,503	38,346	68,579	61,005	58,545
Per share – basic	**0.25**	0.22	0.26	0.25	0.17	0.30	0.27	0.26
Per share – diluted	**0.25**	0.22	0.25	0.25	0.17	0.29	0.26	0.25
Net income (loss)	**(50,546)**	(111)	16,472	(4,826)	18,952	13,004	3,060	3,294
Per share – basic	**(0.23)**	(0.00)	0.07	(0.02)	0.08	0.06	0.01	0.01
Per share – diluted	**(0.23)**	(0.00)	0.07	(0.02)	0.08	0.06	0.01	0.01
Capital expenditures	**22,954**	58,867	25,902	71,243	25,798	78,149	52,674	69,630
Net acquisitions (dispositions)	**250**	3,847	4,771	1,074	(4,823)	–	(5,009)	2,790
Total assets	**1,247,119**	1,369,918	1,336,323	1,349,508	1,264,053	1,291,058	1,237,571	1,240,335
Net debt(1)	**189,481**	213,140	195,892	219,348	179,880	192,184	181,341	186,732
Bank debt	**192,907**	198,971	186,912	189,427	161,495	168,970	156,965	165,750
Decommissioning obligations	**184,846**	222,684	218,950	210,198	193,003	192,409	185,038	182,216

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

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

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flows and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- The Company recorded an impairment charge in Q4 2019 in the amount of $68.0 million on its Cardium oil cash-generating unit ("CGU") due to falling gas and NGL prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The Company recorded an impairment charge in Q4 2018 in the amount of $58.0 million on its Cardium oil CGU due to falling gas prices. In the same period, the Company also recorded an impairment reversal of $53.0 million on its Viking oil CGU resulting in a net impairment expense of $5.0 million in Q4 2018.

Selected Annual Information

	2019	2018 [2]	2017 [2]
Sales volumes			
Natural gas *(mcf/d)*	**53,444**	51,108	48,893
Oil and NGL *(bbls/d)*	**15,165**	15,719	11,987
Average boe/d *(6:1)*	**24,072**	24,237	20,136
Product prices			
Natural gas *($/mcf)*	**2.06**	2.30	2.32
Oil and NGL *($/bbl)*	**61.58**	62.02	55.36
Oil equivalent *($/boe)*	**43.37**	45.08	38.60
(000s, except per share amounts)			
Financial Results			
Gross revenues	**381,066**	398,804	283,672
Net income (loss)	**(39,011)**	38,310	(13,924)
Per share – basic	**(0.17)**	0.17	(0.06)
Per share – diluted	**(0.17)**	0.16	(0.06)
Capital expenditures	**178,966**	226,251	192,302
Net acquisitions (dispositions)	**9,942**	(7,042)	81,971
Total assets	**1,247,119**	1,264,053	1,207,809
Net debt[1]	**189,481**	179,880	173,180
Bank debt	**192,907**	161,495	163,889

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

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 and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange and interest 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.
- 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 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 and NGL prices in the amount of $68.0 million in Q4 2019. In Q4 2018, the Company recorded an impairment charge on its Cardium oil CGU, 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 for a net impairment of $5.0 million. 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.

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 ("E&E") assets–** 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 operating 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 the use of shared infrastructure, geographic proximity, existence of active markets for the Company's products, the way in which management monitors operations and materiality.

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) **IFRS 16** - Judgments are made by management in the application of IFRS 16 related to the incremental borrowing rate and lease term. The incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term. Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

(f) **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.

Future Accounting Pronouncements

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

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

Changes in Accounting Policies

IFRS 16, *Leases*:

Effective January 1, 2019, the Company adopted IFRS 16. The Company has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening deficit and applies the standard prospectively. Therefore, the comparative information in the financial statements has not been restated.

On adoption, management elected to use the following practical expedients permitted under the new standard:

- account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value; and
- the use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "*Leases*". Under the principles of IFRS 16, these leases have been measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 ranged from 4.5% to 8.8% with a weighted average of 5.6%. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019.

Adopting IFRS 16 impacted Tamarack's lease liabilities and ROU assets as follows, as at January 1, 2019:

- recorded lease liabilities of $37.2 million, $25.9 million of which is the current portion; and
- recorded ROU assets of $37.2 million.

Adopting IFRS 16 impacted Tamarack's Q4/19 and the year ended December 31, 2019 financial results compared with what would have occurred had it not adopted the new accounting policy as follows:

- decreased production costs in the amount of $0.8 million and $4.0 million respectively;
- increased DDA&A expenses in the amount of $0.6 million and $2.7 million respectively; and
- increased finance expenses in the amount of $0.2 million and $1.2 million respectively.

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, 2019 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, 2019.

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 Annual Information Form for the year ended December 31, 2019, 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;
- the duration and future direction of the Curtailment Order;
- the impact of the Curtailment Order on Canadian crude prices in 2020;
- the availability, size, terms, use and renewal of the Facility;
- the performance of the Viking waterflood project, including oil recoveries and , corporate decline rates and production rates in 2020 and 2021; Tamarack's commitment to its environmental, social and governance responsibilities;
- 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 intention 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 expectation of generating adjusted funds flow that exceeds its budgeted capital expenditures (excluding tuck-in acquisitions);
- Tamarack's position to withstand further crude oil price volatility;

- future drilling plans;
- 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;
- future investment and capital allocation strategy;
- planned waterflood investment in 2020 and expected well conversions and drilling of additional injection wells;
- Tamarack's 2020 budget and 2020 guidance levels;
- Tamarack's execution to be fully self-funded in 2020;
- estimates for debt-adjusted production per share in 2020;
- expectations as to royalty rates as a percentage of revenue;
- contractual obligations and commitments;
- the estimates used to calculate the decommissioning obligations and depletion of PP&E;
- expectations for realized commodity prices in 2020;
- Tamarack's intent to use excess total adjusted funds flows to purchase and cancel shares under the NCIB or to close additional accretive tuck-in acquisitions;
- future RSU settlements;
- Tamarack's expectation of challenging market conditions for the long term;
- Tamarack's expectation of risk mitigation and realized price improvements from exposure to diversified gas markets;
- expectations for oil, NGL and natural gas pricing in 2020 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2020.

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 ability to explore diversified gas markets;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the base curtailment limits and expected duration of the Curtailment Order;
- drilling results, including field production rates and decline rates;
- decrease in corporate declines in 2020 and 2021 as a result of the positive response from ongoing waterflood development;
- 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 Expense", "Interest Expense", "Depletion, Depreciation, Amortization and Accretion ("DDA&A")", "Impairment", "Income Taxes", "Adjusted Funds Flow and Net Income (Loss)", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Property Acquisitions", "Share Capital", "Liquidity and Capital Resources", "Bank Debt", "Guidance", "Commitments", "Contingency", "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 markets 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, 2019, 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 funds flow, operating netback, net debt to annualized adjusted funds flow ratio, capital cost payout, net 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.