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 and six months ended June 30, 2019 and 2018. This MD&A is dated and based on information available as at August 8, 2019 and should be read in conjunction with the unaudited condensed consolidated interim financial statements ("interim financial statements") and the notes thereto for the three and six months ended June 30, 2019 and 2018. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The interim financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting". 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 19. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q2 2019 Financial and Operating Highlights

- Production averaged 24,090 boe/d (63% oil and NGL weighting) reflecting the Company's compliance with the production curtailment order imposed by the Government of Alberta that came into effect on January 1, 2019 (the "Curtailment Order"). Tamarack adjusted the timing of its capital investment and activity in order to comply with the Curtailment Order.
- Total adjusted operating field netback (see "Non-IFRS Measures") in Q2/19 was $57.9 million ($0.26/share basic and $0.25/share diluted), 1% higher than the $57.5 million generated in Q1/19 ($0.25/share basic and diluted).
- Operating netback (see "Non-IFRS Measures") of $29.14/boe in Q2/19 was 3% lower than the Q1/19 netback of $30.11/boe primarily due to a higher realized commodity hedging loss in the second quarter compared to the previous quarter.
- Net production and transportation expenses in Q2/19 were 3% lower at $10.12/boe compared to $10.48/boe in Q2/18 primarily due to increased production from the lower-cost Veteran area and a reduction in transportation expenses for oil produced at Veteran as a result of the recently commissioned pipeline in the Provost area of Alberta (the "Provost Pipeline").
- Invested $25.9 million in the quarter, with 61% directed to drill, complete and equip 5.0 net Viking oil wells, as well as complete and bring on production 18 (17.7 net) Viking oil wells and 2.0 net Cardium oil wells that were drilled in late Q1/19. The Company drilled 5.0 net Viking oil wells and four (3.5

net) Cardium oil wells that will be brought on production in Q3/19, as well as 2.0 net wells at Veteran that will be used for injection and water sourcing to further contribute to the Company's waterflood program in the area.

- Completed a $4.8 million Viking oil acquisition in the Veteran/Consort area of Alberta, adding 130 boe/d and 9.4 net sections of undeveloped Viking land.

Production

Quarter-over-Quarter

	Q2 2019	Q1 2019	% change
Production			
Light oil (bbls/d)	**13,237**	12,689	4
Heavy oil (bbls/d)	**521**	483	8
Natural gas liquids ("NGL") (bbls/d)	**1,423**	1,548	(8)
Natural gas (mcf/d)	**53,451**	50,576	6
Total (boe/d)	**24,090**	23,149	4
Percentage of oil and NGL	**63%**	64%	(2)

Average production for Q2/19 increased 4% from the previous quarter as a result of 18 Viking oil wells and two Cardium oil wells coming on-stream which were drilled and awaiting completion at the end of the first quarter. By adjusting the timing of drilling and completion activity in the first half of 2019 rather than shutting-in wells to comply with the Curtailment Order, the Company was able to rely on the expected base production declines to remain below the imposed production limits. The Company's drilling program added 1,672 boe/d in Veteran (77% oil and NGL), 1,367 boe/d in Wilson Creek/Alder Flats (67% oil and NGL) and 77 boe/d in Penny (97% oil and NGL).

In the second quarter of 2019, the Company's oil and NGL weighting was 63% compared to 64% in the first quarter of 2019. While complying with the Curtailment Order, the Company expects its oil and NGL weighting to remain stable and average between 63% and 66% for the remainder of the year.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
	2019	2018	% change	**2019**	2018	% change
Production						
Light oil (bbls/d)	**13,237**	13,242	–	**12,965**	13,240	(2)
Heavy oil (bbls/d)	**521**	527	(1)	**502**	414	21
NGL (bbls/d)	**1,423**	1,355	5	**1,485**	1,351	10
Natural gas (mcf/d)	**53,451**	52,376	2	**52,022**	52,129	–
Total (boe/d)	**24,090**	23,853	1	**23,622**	23,693	–
Percentage of oil and NGL	**63%**	63%	–	**63%**	63%	–

Average production for both the second quarter of 2019 and the first six months of 2019 were comparable to the same periods in 2018.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q2 2019	Q1 2019	% change
Revenue ($ thousands)			
Oil and NGL	**$90,434**	$82,232	10
Natural gas	**8,307**	12,815	(35)
Total	**$98,741**	$95,047	4
Average realized price:			
Light oil ($/bbl)	**70.17**	65.47	7
Heavy oil ($/bbl)	**65.14**	40.65	60
NGL ($/bbl)	**21.81**	40.85	(47)
Combined average oil and NGL ($/boe)	**65.46**	62.07	5
Natural gas ($/mcf)	**1.71**	2.82	(39)
Revenue ($/boe)	**45.04**	45.62	(1)
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**59.81**	54.84	9
Edmonton Par (Cdn$/bbl)	**72.63**	67.44	8
Hardisty Heavy (Cdn$/bbl)	**63.29**	59.12	7
NYMEX daily index (US$/mmbtu)	**2.69**	3.16	(15)
AECO daily index (Cdn$/mcf)	**1.03**	2.59	(60)
AECO monthly index (Cdn$/mcf)	**1.16**	1.94	(40)

Revenue from oil, natural gas and NGL sales in Q2/19 was in line with Q1/19, reflecting a 1% decline on a per boe basis. Due 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, have resulted in a significant narrowing of the WTI/Edmonton Par differential to date in 2019.

Despite its decrease subsequent to the end of the second quarter of 2019, the average WTI price during Q2/19 remained higher than Q1/19, increasing 9% to $59.81/bbl in Q2/19 from $54.84/bbl in Q1/19. In addition, the average WTI/Edmonton Par light oil differential narrowed during the quarter from US$4.79/bbl in Q1/19 to US$4.57/bbl in Q2/19. This decrease, compounded with the improved WTI price, resulted in an average Edmonton Par price of C$72.63/bbl in Q2/19 compared to C$67.44/bbl in Q1/19. Tamarack's realized light oil wellhead price for the three months ended June 30, 2019 increased 7% to $70.17/bbl from $65.47/bbl in the previous quarter, reflecting a similar change to that experienced by the benchmark over the same period.

Although the improved light sweet differential is a positive short-term development, Tamarack believes potential differential widening poses a risk to Canadian crude prices in the second half of 2019 and through 2020 unless the Curtailment Order remains in effect. At present, the future direction of the Curtailment Order is unclear 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 has introduced further pricing risk. At present, Tamarack has approximately 50% of forecasted 2019 oil production protected with differential hedges. While the timing, duration and magnitude of extreme oil price conditions are difficult to predict, Tamarack is committed to conservatively planning and continues to explore ways to mitigate and manage market risk through financial and physical hedges as well as alternate market delivery options.

As expected, realized NGL prices decreased 47% to $21.81/bbl in Q2/19 from $40.85/bbl in Q1/19. This decrease is due largely to material changes in the NGL market during the contract negotiation season. In particular, Alberta spot butane markets have continued to struggle after plummeting in the second half of 2018. Butane prices that were historically valued at 50% to 60% of WTI, weakened to trade at 5% to 15% of WTI in the early part of 2019, resulting in materially lower prices for the 2019 to 2020 NGL contract season. Currently, NGL supply outstrips demand and prices are impacted by a lack of pipeline egress in Canada. In addition, frac fees increased by approximately 30% to 35% for the 2019 to 2020 contract season. Consequently, the realized prices for the remainder of 2019 and the first quarter of 2020 are expected to be materially lower than the prior contract period. These lower realized prices will persist at a minimum until the next contract year, which begins April 1, 2020.

Tamarack's realized natural gas price decreased 39% in the second quarter to $1.71/mcf from $2.82/mcf in Q1/19. Similarly, the AECO daily benchmark price decreased 60% quarter-over-quarter to $1.03/mcf from $2.59/mcf, while NYMEX monthly settlement price decreased 15% to US$2.69/mmbtu in Q2/19 from US$3.16/mmbtu in Q1/19. The decrease in Tamarack's realized price compared to the previous quarter was largely a result of reduced demand for natural gas in Canada stemming from mild temperatures in Western Canada. Tamarack's exposure to alternate gas markets continued to benefit the Company's realized price. Despite a lower realized price relative to prior quarters, realized gas prices continued to significantly exceed the AECO pricing benchmark.

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

Natural Gas Market	**Percentage Exposure (as at June 30, 2019)**
NYMEX (Physical Basis Swap)	26.6
AECO Daily (5A)	19.8
Malin	15.0
Waddington	9.6
Dawn	7.5
Chicago	7.5
Michigan City Gate	7.5
AECO Daily (5A) + premium (SK)	6.5
	100%

Oversupply and takeaway capacity restrictions continue to create downward pricing pressure and volatility in the Alberta natural gas markets. Despite industry proposals for a voluntary natural gas curtailment solution, Tamarack anticipates volatile and depressed AECO market prices will continue through 2019 and beyond. Tamarack continues to benefit from multiple third-party gas sales contracts having various end dates until 2022. These contracts provide diversification of the Company's natural gas price exposure and help to mitigate individual market volatility risk. Through the second quarter of 2019, more than 50% of Tamarack's total natural gas production was priced at alternate markets to AECO, including Malin, Chicago, Michigan Consolidated, Dawn, Waddington 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 June 30,			Six months ended June 30,		
	2019	2018	% change	**2019**	2018	% change
Revenue ($ thousands)						
Oil and NGL	**$90,434**	$100,002	(10)	**$172,666**	$188,228	(8)
Natural gas	**8,307**	7,857	6	**21,122**	18,367	15
Total	**$98,741**	$107,859	(8)	**$193,788**	$206,595	(6)
Average realized price:						
Light oil ($/bbl)	**70.17**	75.29	(7)	**67.88**	71.98	(6)
Heavy oil ($/bbl)	**65.14**	70.17	(7)	**53.43**	61.20	(13)
NGL ($/bbl)	**21.81**	45.90	(52)	**31.68**	45.53	(30)
Combined average oil and NGL ($/boe)	**65.46**	72.66	(10)	**63.80**	69.30	(8)
Natural gas ($/mcf)	**1.71**	1.65	4	**2.24**	1.95	15
Revenue ($/boe)	**45.04**	49.69	(9)	**45.32**	48.17	(6)
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**59.81**	67.88	(12)	**57.34**	65.41	(12)
Edmonton Par (Cdn$/bbl)	**72.63**	78.90	(8)	**70.05**	75.62	(7)
Hardisty Heavy (Cdn$/bbl)	**63.29**	64.40	(2)	**61.22**	55.70	10
NYMEX daily index (US$/mmbtu)	**2.69**	2.77	(3)	**2.92**	2.87	2
AECO daily index (Cdn$/mcf)	**1.03**	1.18	(13)	**1.81**	1.62	12
AECO monthly index (Cdn$/mcf)	**1.16**	1.02	14	**1.55**	1.43	8

Revenue from oil, natural gas and NGL sales for the three and six months ended June 30, 2019 decreased by 8% and 6%, respectively, compared to the same periods in 2018, primarily due to the decrease in crude oil and NGL prices offset by the increase in realized 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 June 30, 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	900 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $65.87
Crude oil	200 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US $61.00
Crude oil	3,105 bbls/day	July 1, 2019 – September 30, 2019	WTI put option	US $60.00
Crude oil	2,990 bbls/day	October 1, 2019 – December 31, 2019	WTI put option	US $60.00
Crude oil	4,000 bbls/day	July 1, 2019 – December 31, 2019	WTI/Edm par differential	US ($12.13)
Crude oil	3,000 bbls/day	August 1, 2019 – December 31, 2019	WTI/Edm par differential	US ($7.70)
Foreign exchange	5,750,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3065
Foreign exchange	5,250,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.3140
Foreign exchange	1,000,000 US$/mth	January 1, 2020 – March 31, 2020	Exchange rate	Cdn $1.3405
Interest rate	25,000,000 US$/mth	July 1, 2019 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US$/mth	July 1, 2019 – June 14, 2023	Fixed rate	1.75%

At June 30, 2019, the commodity, foreign exchange and interest rate contracts were fair valued with a liability of $0.9 million (December 31, 2018 - $19.7 million asset) recorded on the balance sheet and an unrealized loss of $20.6 million recorded in earnings for the six months ended June 30, 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 June 30, 2019, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	2,500 mmbtu/day	July 1, 2019 – October 31, 2019	AECO fixed price	Cdn $1.75
Natural gas	10,000 mmbtu/day	July 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	5,000 mmbtu/day	October 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.46
Natural gas	15,000 mmbtu/day	November 1, 2019 – November 30, 2019	AECO/Henry Hub differential	Index – US $1.31
Natural gas	15,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.41
Natural gas	15,000 mmbtu/day	December 1, 2019 – December 31, 2019	AECO/Henry Hub differential	Index – US $1.22

Since June 30, 2019, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US ($9.50)
Crude oil	2,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US ($7.95)

Since June 30, 2019, the Company has entered into the following physical contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	2,500 GJs/day	July 1, 2019 – September 30, 2019	AECO fixed price	Cdn $0.85
Natural gas	5,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $0.95
Natural gas	5,000 mmbtu/day	April 1, 2020 – October 31, 2020	AECO/Henry Hub differential	Index – US $1.35

Royalties

Quarter-over-Quarter

	Q2 2019	Q1 2019	% change
Royalty expenses ($ thousands)	**$9,211**	$10,117	(9)
$/boe	**4.20**	4.86	(14)
percent of sales	**9**	11	(18)

Royalties as a percentage of revenue were lower in the second quarter of 2019 compared to the first quarter of 2019, due to prior period gas cost allowance adjustments that were recorded in Q2 2019.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
	2019	2018	% change	**2019**	2018	% change
Royalty expenses ($ thousands)	**$9,211**	$10,986	(16)	**$19,328**	$21,924	(12)
$/boe	**4.20**	5.06	(17)	**4.52**	5.11	(12)
percent of sales	**9**	10	(10)	**10**	11	(9)

Royalties as a percentage of revenue were lower for both the three and six months ended June 30, 2019 compared to the same periods in 2018 due to prior period gas cost allowance adjustments that were recorded in Q2 2019. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for the remainder of 2019 based on current forecast commodity price levels.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2019**	Q1 2019	% change
Production and transportation expenses	**$21,959**	$21,825	1
Less: processing income (expense)	**(215)**	571	(138)
Total net production and transportation expenses	**$22,174**	$21,254	4
Total ($/boe)	**$10.12**	$10.20	(1)

Net production and transportation expenses per boe between the second and first quarters of 2019 were comparable.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2019**	2018 (1)	% change	**2019**	2018 (1)	% change
Production and transportation expenses	**$21,959**	$22,465	(2)	**$43,784**	$45,579	(4)
Less: processing income (expense)	**(215)**	(274)	(22)	**356**	62	474
Total net production and transportation expenses	**$22,174**	$22,739	(2)	**$43,428**	$45,517	(5)
Total ($/boe)	**$10.12**	$10.48	(3)	**$10.16**	$10.61	(4)

(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 and six months ended June 30, 2019, net production and transportation expenses per boe were lower compared to the same periods in 2018. This is the result of the net impact of reduced transportation costs in the Veteran area related to the Provost Pipeline that eliminated the trucking of sales oil as of 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)	**Q2 2019**	Q1 2019	% change
Average realized sales	**$45.04**	$45.62	(1)
Royalty expenses	**(4.20)**	(4.86)	(14)
Net production and transportation expenses	**(10.12)**	(10.20)	(1)
Operating field netback	**30.72**	30.56	1
Realized commodity hedging loss	**(1.58)**	(0.45)	251
Operating netback	**$29.14**	$30.11	(3)

The Company's operating netback (see "Non-IFRS Measures") decreased 3% in the second quarter of 2019 compared to the first quarter of 2019. This was primarily due to a higher realized commodity hedging loss in the second quarter compared to the previous quarter.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2019**	2018 (1)	% change	**2019**	2018 (1)	% change
Average realized sales	**$45.04**	$49.69	(9)	**$45.32**	$48.17	(6)
Royalty expenses	**(4.20)**	(5.06)	(17)	**(4.52)**	(5.11)	(12)
Net production and transportation expenses	**(10.12)**	(10.48)	(3)	**(10.16)**	(10.61)	(4)
Operating field netback	**30.72**	34.15	(10)	**30.64**	32.45	(6)
Realized commodity hedging loss	**(1.58)**	(3.36)	(53)	**(1.03)**	(1.99)	(48)
Operating netback	**$29.14**	$30.79	(5)	**$29.61**	$30.46	(3)

(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 and six months ended June 30, 2019, operating netbacks (see "Non-IFRS Measures") were lower than the same periods in 2018 due to higher realized oil prices in 2018, partially offset by lower realized hedging losses in 2019 and higher royalty expense per boe in 2018.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2019**	Q1 2019	% change
Gross costs	**$4,065**	$3,860	5
Capitalized costs and recoveries	**(947)**	(900)	5
General and administrative costs	**$3,118**	$2,960	5
Total ($/boe)	**$1.42**	$1.42	–

Gross and net G&A expenses were slightly higher during the second quarter of 2019 than in the first quarter of 2019. G&A expenses on a per boe basis remained consistent quarter-over-quarter.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2019**	2018	% change	**2019**	2018	% change
Gross costs	**$4,065**	$4,191	(3)	**$7,925**	$8,415	(6)
Capitalized costs and recoveries	**(947)**	(817)	16	**(1,847)**	(1,662)	11
General and administrative costs	**$3,118**	$3,374	(8)	**$6,078**	$6,753	(10)
Total ($/boe)	**$1.42**	$1.55	(8)	**$1.42**	$1.57	(10)

Gross and net G&A costs decreased for the three and six months ended June 30, 2019, compared to the same periods in 2018, due to a continued focus on cutting non-essential G&A costs. Net per boe G&A costs for the three and six months ended June 30, 2019 were lower than the same periods in 2018 due to lower overall gross and net G&A expenses.

Stock-Based Compensation Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2019**	Q1 2019	% change
Gross costs	**$3,075**	$1,788	72
Capitalized costs	**(676)**	(468)	44
Total stock-based compensation	**$2,399**	$1,320	82
Total ($/boe)	**$1.09**	$0.63	73

Stock-based compensation expense related to stock options (“Options”), restricted share units (“RSUs”) and performance share units (“PSUs”) was higher in Q2/19 than in Q1/19 due to a full quarter of stock-based compensation associated with the 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.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2019**	2018	% change	**2019**	2018	% change
Gross costs	**$3,075**	$2,218	39	**$4,863**	$4,256	14
Capitalized costs	**(676)**	(757)	(11)	**(1,144)**	(1,281)	(11)
Total stock-based compensation	**$2,399**	$1,461	64	**$3,719**	$2,975	25
Total ($/boe)	**$1.09**	$0.67	63	**$0.87**	$0.69	26

Stock-based compensation expense related to Options, RSUs and PSUs for the three and six months ended June 30, 2019 was higher compared to the same periods in 2018 due to a full quarter of stock-based compensation associated with the Options, RSUs and PSUs that were issued late in Q1 2019 and due to an increase in employees who are eligible for the long-term incentive program. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

During the six months ended June 30, 2019, the Company issued 0.4 million Options (at a weighted average exercise price of $2.57 per share), 2.5 million RSUs and 1.1 million PSUs compared to 0.2 million Options (at a weighted average exercise price of $2.62 per share), 2.4 million RSUs and no PSUs during the same period in 2018.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2019**	Q1 2019	% change
Interest on bank debt	**$2,038**	$1,707	19
Costs associated with credit facility renewal	**580**	56	936
Interest on lease liabilities	**253**	511	(50)
Total interest expense	**$2,871**	$2,274	26
Total ($/boe)	**$1.31**	$1.09	20
Average drawings on bank debt	**$196,278**	$174,745	12

Interest expense was higher in the second quarter of 2019 compared to the previous quarter due to a higher average amount drawn quarter-over-quarter on the revolving credit facility and the costs associated with the credit facility renewal.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2019**	2018 (1)	% change	**2019**	2018 (1)	% change
Interest on bank debt	**$2,038**	$2,113	(4)	**$3,745**	$3,951	(5)
Costs associated with credit facility renewal	**580**	349	66	**636**	352	81
Interest on lease liabilities	**253**	–	–	**764**	–	–
Total interest expense	**$2,871**	$2,462	17	**$5,145**	$4,303	20
Total ($/boe)	**$1.31**	$1.13	16	**$1.20**	$1.00	20
Average drawings on bank debt	**$196,278**	$156,504	25	**$185,512**	$160,587	16

(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.

Interest expense for the three and six months ended June 30, 2019 was higher than the same periods in 2018 due to the Company adopting IFRS 16 in 2019 and the higher average amount drawn on the revolving credit facility, offset by increased utilization of lower interest rate options that were available through the Company's syndicate of lenders, as well as favourable market conditions in 2019.

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

The Company depletes its property, plant and equipment ("PP&E") based on its proved plus probable reserves and depreciates its right-of-use ("ROU") assets on a straight-line basis over the shorter of the estimated useful life or the lease term or, 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, 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)	**Q2 2019**	Q1 2019	% change
Depletion and depreciation	**$41,533**	$39,124	6
Amortization of undeveloped leases	**239**	228	5
Accretion	**1,026**	1,145	(10)
Total	**$42,798**	$40,497	6
Depletion and depreciation ($/boe)	**$18.95**	$18.78	1
Amortization ($/boe)	**0.11**	0.11	–
Accretion ($/boe)	**0.47**	0.55	(15)
Total ($/boe)	**$19.53**	$19.44	–

DDA&A expense per boe for the second and first quarter of 2019 were similar. On an absolute basis, DDA&A expense was higher due to an increase in production volumes.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2019**	2018 (1)	% change	**2019**	2018 (1)	% change
Depletion and depreciation	**$41,533**	$43,307	(4)	**$80,657**	$86,591	(7)
Amortization of undeveloped leases	**239**	294	(19)	**467**	468	–
Accretion	**1,026**	1,015	1	**2,171**	2,022	7
Total	**$42,798**	$44,616	(4)	**$83,295**	$89,081	(6)
Depletion and depreciation ($/boe)	**$18.95**	$19.95	(5)	**$18.86**	$20.19	(7)
Amortization ($/boe)	**0.11**	0.14	(21)	**0.11**	0.11	–
Accretion ($/boe)	**0.47**	0.47	–	**0.51**	0.47	9
Total ($/boe)	**$19.53**	$20.56	(5)	**$19.48**	$20.77	(6)

(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 and six months ended June 30, 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 year-end independent reserves evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2018 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 the three and six months ended June 30, 2019 due to the lower DDA&A expense per boe.

Income Taxes

The Company did not incur any cash tax expense for the three and six months ended June 30, 2019 and does not expect to pay any cash tax in 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

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%. For Q2 2019 and YTD 2019, the deferred income tax recovery includes $6.5 million attributable to these tax rate decreases.

For the three and six months ended June 30, 2019, a deferred income tax recovery of $2.5 million and $3.8 million, respectively, was recognized compared to a deferred income tax expense of $1.7 million and $3.5 million for the same periods in 2018.

Adjusted Operating Field Netback and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q2 2019**	Q1 2019	% change
Income (loss) before taxes	**$13,960**	$(6,123)	(328)
Depletion, depreciation and amortization	**41,772**	39,352	6
Stock-based compensation	**2,399**	1,320	82
Accretion expense on decommissioning obligations	**1,026**	1,145	(10)
Unrealized (gain) loss on financial instruments	**(1,251)**	21,809	(106)
Adjusted operating field netback	**$57,906**	$57,503	1
Per share - basic	**$0.26**	$0.25	4
Per share - diluted	**$0.25**	$0.25	–
Net income (loss)	**$16,472**	$(4,826)	(441)
Per share - basic	**$0.07**	$(0.02)	(450)
Per share - diluted	**$0.07**	$(0.02)	(450)

The adjusted operating field netback (see “Non-IFRS Measures”) during the second quarter of 2019 was comparable to the first quarter of 2019.

The Company recorded net income of $16.5 million ($0.07 per share basic and diluted) during the three months ended June 30, 2019, compared to a net loss of $4.8 million ($0.02 per share basic and diluted) during the previous quarter. This was primarily due to an unrealized hedging gain in Q2/19 compared to an unrealized hedging loss in Q1/19 and the reduction in the Alberta corporate income tax rate which resulted in a deferred income tax recovery in Q2/19.

Year-over-Year

($ thousands, except per boe)	Three months ended June 30, 2019	2018 (1)	% change	Six months ended June 30, 2019	2018 (1)	% change
Income before taxes	**$13,960**	$4,731	195	**$7,837**	$9,804	(20)
Depletion, depreciation and amortization	**41,772**	43,601	(4)	**81,124**	87,059	(7)
Stock-based compensation	**2,399**	1,461	64	**3,719**	2,975	25
Gain on disposition of property, plant and equipment	**–**	–	–	**–**	(6)	(100)
Accretion expense on decommissioning obligations	**1,026**	1,015	1	**2,171**	2,022	7
Unrealized (gain) loss on financial instruments	**(1,251)**	10,197	(112)	**20,558**	17,696	16
Adjusted operating field netback	**$57,906**	$61,005	(5)	**$115,409**	$119,550	(3)
Per share - basic	**$0.26**	$0.27	(4)	**$0.51**	$0.52	(2)
Per share - diluted	**$0.25**	$0.26	(4)	**$0.50**	$0.51	(2)
Net income	**$16,472**	$3,060	438	**$11,646**	$6,354	83
Per share - basic	**$0.07**	$0.01	600	**$0.05**	$0.03	67
Per share - diluted	**$0.07**	$0.01	600	**$0.05**	$0.03	67

(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 operating field netback (see “Non-IFRS Measures”) for the three and six months ended June 30, 2019 was lower compared to the same periods in 2018. This was primarily due to weaker crude oil and NGL prices.

The Company recorded net income of $16.5 million ($0.07 per share basic and diluted) and $11.6 million ($0.05 per share basic and diluted), respectively, during the three and six months ended June 30, 2019, compared to net income of $3.1 million ($0.01 per share basic and diluted) and $6.4 million ($0.03 per share basic and diluted) for the same periods in 2018.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

($ thousands)	Three months ended June 30, 2019	2018	% change	Six months ended June 30, 2019	2018	% change
Land	**$167**	$2,524	(93)	**$174**	$3,311	(95)
Geological and geophysical	**3**	11	(73)	**3**	13	(77)
Drilling and completion	**15,676**	36,848	(57)	**69,862**	90,034	(22)
Equipment and facilities	**9,089**	12,564	(28)	**25,384**	27,463	(8)
Capitalized G&A	**805**	690	17	**1,500**	1,380	9
Office equipment	**162**	37	338	**222**	103	116
Total capital expenditures	**$25,902**	$52,674	(51)	**$97,145**	$122,304	(21)

During the second quarter of 2019, the Company drilled, completed and equipped 5.0 net Viking oil wells. In addition to the second quarter drilling program, the Company also completed and brought on production 18 (17.7 net) Viking oil wells and 2.0 net Cardium oil wells that were drilled in late Q1/19. The Company also drilled 5.0 net Viking oil wells and four (3.5 net) Cardium oil wells that will be brought on production in Q3/19, resulting in total drilling for the quarter of 10.0 net Viking oil wells and four (3.5 net) Cardium oil wells.

Tamarack also directed capital to the continued development of a waterflood program in the Company's Veteran, Alberta area and drilled an additional 2.0 net wells at Veteran during the quarter. One of these wells will be used as an injection well and the other will be used as a water source well. 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 six months ended June 30, 2019 Drilling Summary	
	Gross	Net
Viking	59.0	57.9
Cardium	13.0	11.6
Penny	2.0	2.0
Water source and injectors	2.0	2.0
	76.0	73.5

As at June 30, 2019, the Company's net undeveloped land totaled 415,845 acres.

Property Acquisitions

During the second quarter of 2019, Tamarack completed a $4.8 million Viking oil acquisition in the Veteran/Consort area of Alberta, adding 130 boe/d and 9.4 net sections of undeveloped lands that are adjacent to existing Tamarack acreage.

Share Capital

At June 30, 2019, Tamarack had issued and outstanding 225,488,743 common shares ("Common Shares"), including 1,027,694 held in treasury, 2,611,333 Options, 8,654,619 RSUs and 2,093,100 PSUs. At August 8, 2019, Tamarack has issued and outstanding 225,715,076 Common Shares including 748,361 held in treasury, 2,611,333 Options, 8,375,286 RSUs and 2,093,100 PSUs. This compares to December 31, 2018, at which time Tamarack had issued and outstanding 226,072,693 Common Shares, including 1,193,188 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 June 30, 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.

As noted under 'Liquidity and Capital Resources' below, during the six months ended June 30, 2019, Tamarack purchased and cancelled 926,900 outstanding Common Shares under its normal course issuer bid ("NCIB") program, for a total investment of $2.2 million. During the year ended December 31, 2018, 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)	**June 30, 2019**	June 30, 2018 (1)	December 31, 2018 (1)
Working capital deficiency	**$8,980**	$24,376	$18,385
Bank debt	**186,912**	156,965	161,495
Net debt	**195,892**	181,341	179,880
Quarterly adjusted operating field netback	**$57,906**	$61,005	$38,346
Annualized factor	**4**	4	4
Annualized adjusted operating field netback	**231,624**	244,020	153,384
Net debt to annualized adjusted operating field netback	**0.8x**	0.7x	1.2x

(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 but excluding the fair value of financial instruments and lease liabilities, totaled $195.9 million as at June 30, 2019. This compares to its net debt of $219.3 million and $181.3 million in Q1/19 and Q2/18, respectively. Tamarack's Q2/19 net debt to annualized adjusted operating field netback ratio (see "Non-IFRS Measures") was 0.8 times.

The $30.7 million invested in capital expenditures and property acquisitions during the second quarter of 2019 was funded completely by Tamarack's adjusted operating field netback (see "Non-IFRS Measures") of $57.9 million.

With continued commodity price volatility and crude oil price differential volatility that has impacted the Canadian oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by adjusting capital spending as appropriate to respond to changes in realized commodity prices and by using financial derivatives and physical delivery contracts to mitigate risk. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas, whether by increasing drilling activity, 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 six months ended June 30, 2019, the Company spent $2.2 million to purchase and cancel 926,900 outstanding Common Shares under the NCIB program.

Over and above the NCIB program, during the second quarter of 2019, the Company also directed $1.25 million to purchase of 498,700 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. 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 June 30, 2019, the remaining balance of purchased Common Shares held in trust totaled 1,027,694.

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 $186.9 million was drawn as of June 30, 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.

During the semi-annual review of the Facility that occurred during the fourth quarter of 2018, an accordion feature was added to the lending agreement 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 June 30, 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 June 30, 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 November 30, 2019.

There are no financial covenants governing the Facility.

Guidance

Tamarack's first half production of 23,622 boe/d (63% oil and NGL weighting) was in line with its guidance forecast of 23,500 boe/d to 23,750 boe/d. Production continues to be impacted by the Company's required compliance with the Curtailment Order, which muted the Company's 2018 growth trajectory as the timing of capital spending and activity were adjusted. With the assumption that the Curtailment Order will be extended to the end of 2019, Tamarack will continue to adjust the timing of its drilling program to continue to comply with the Curtailment Order. The Company's full year guidance remains intact, including plans to invest between $170 million and $180 million (excluding tuck-in acquisitions), which is expected to be more than funded by total adjusted operating field netback (see "Non-IFRS Measures") based on current WTI prices above US$55/bbl.

Under the original capital expenditure budget, Tamarack forecast the drilling of 125 net wells, including Viking wells in Alberta and Saskatchewan, Cardium oil wells in Wilson Creek and oil wells in Penny. However, in response to the expected extension of the Curtailment Order through the second half of 2019 and legacy production performance, Tamarack's planned activities have been adjusted, including reducing its 2019 forecast drilling count to approximately 117 net wells. In addition, the Company intends to redirect drilling capital from its Alberta Viking area to the Saskatchewan Viking play, where associated natural gas rates are slightly higher. As a result, Tamarack expects exit production will reflect a modestly lower oil and NGL weighting (62 to 65%) with exit production anticipated to be at the lower end of the guidance range of 25,500 boe/d, and a slight tightening of the upper end to 25,750 boe/d.

In light of the Veteran waterflood results to date, the Company also elected to shift a portion of its second half 2019 drilling capital to the waterflood program. Approximately $5 to $7 million of capital that was earmarked for Viking drills under the original budget will be directed to the Veteran waterflood adding an additional six Veteran injector wells. This shift will increase the total number of injector wells at Veteran from 21 to 27 and will also add three incremental new water source wells by year end. Although the impact of the waterflood on overall corporate decline rates is expected to be realized starting in 2020, this second half 2019 capital reallocation decision clearly supports the Company's long-term sustainability and demonstrates the outperformance of its legacy production volumes given reduced drilling with no change to production guidance ranges.

Tamarack intends to continue assessing capital allocation decisions in light of future commodity prices with the view to optimizing balance sheet strength and per share metrics while remaining compliant with the Curtailment Order. Due to Tamarack's success in accumulating an inventory of Viking and Cardium locations that payout in 1.5 years or less at current commodity prices, the Company expects to be fully self-funding in 2019 and estimates it will achieve a 3% to 5% increase in debt adjusted production per share[1] (see "Non-IFRS Measures") in Q4/19 compared to Q4/18. Further, based on forward strip prices, Tamarack's 2019 capital program is forecast to generate approximately $40 million to $50 million of adjusted operating field netback (see "Non-IFRS Measures") over and above budgeted capital expenditures (excluding tuck-in acquisitions), which can be directed to further asset enhancements or incremental share buy-backs under its active NCIB program. Without the shift in capital to the waterflood, the excess adjusted operating field netback (see "Non-IFRS Measures") would have been even higher, while still enabling the Company to meet production guidance, which demonstrates the strength of Tamarack's business model.

The Company's capital allocation strategy over the past several years has remained consistent with the objective of achieving sustainability at low oil prices, while generating debt-adjusted production per share growth. With approximately 30% of its 2019 production protected with hedges including a US$60.00/bbl WTI put option and another approximately 3% protected by fixed price contracts at US$64.60/bbl, Tamarack remains well positioned to withstand further crude oil price volatility.

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

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

	2019 Guidance
Average annual production (boe/d)	23,500 – 24,500
Liquids weighting (%)	~64 – 66
Exit production without Curtailment (boe/d)	25,500 – 26,500
Liquids weighting (%)	~64 – 66
Exit production with Curtailment (boe/d)	25,500 – 25,750
Liquids weighting (%)	~62 – 65
2019 Capital expenditures ($millions)	$170 – 180
2019 price assumptions:	
WTI ($US/bbl)	$50.00
Edmonton Par ($CDN/bbl)	$52.33
Edmonton Par differential ($US/bbl)	$10.75
AECO ($CDN/GJ)	$1.31
Canadian/US dollar exchange rate	$0.75

Should forecasted realized commodity prices significantly fluctuate from levels outlined in the assumptions above, Tamarack maintains control to accelerate or reduce capital expenditures, redirect capital to purchase Common 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 June 30, 2019:

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Bank debt	-	–	186,912	–	–	–	–
Office lease(1)	271	263	–	–	–	–	–
Take or pay commitments(2)	1,103	2,256	2,294	2,340	2,396	–	–
Gas transportation(3)	365	229	76	–	–	–	–
Total	1,739	2,748	189,282	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

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

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

(b) **Operating Netback and Operating Field netback -** Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. These benchmarks do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity, 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 8 in the section titled "Operating Netback".

(c) **Net Debt -** Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The Company uses net debt (bank debt plus working capital surplus or deficit, 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):

($ thousand)	June 30, 2019	December 31, 2018 [(1)]
Accounts payable and accrued liabilities	$42,071	$41,966
Accounts receivable	(29,240)	(21,211)
Prepaid expenses and deposits	(3,851)	(2,370)
Working capital deficiency	8,980	18,385
Bank debt	186,912	161,495
Net debt	$195,892	$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 Operating Field Netback** – Management uses certain industry benchmarks, such as net debt to annualized adjusted operating field netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated as net debt divided by the annualized adjusted operating field netback for the most recently completed quarter. Management considers net debt to annualized adjusted operating field netback as a key measure as it provides a snapshot of the overall financial health of a company and its ability to pay off its debt and take on new debt, if necessary, using the most recent quarter's results.

(f) **Debt-Adjusted Production per Share Growth** - Management uses certain measurements 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	**Jun. 30, 2019**	Mar. 31, 2019	Dec. 31, 2018 (2)	Sep. 30, 2018 (2)	Jun. 30, 2018 (2)	Mar. 31, 2018 (2)	Dec. 31, 2017 (2)	Sep. 30, 2017 (2)
Sales volumes								
Natural gas *(mcf/d)*	**53,451**	50,576	50,262	49,943	52,376	51,879	51,956	49,987
Oil and NGL *(bbls/d)*	**15,181**	14,720	16,403	16,441	15,124	14,885	14,148	12,210
Average boe/d *(6:1)*	**24,090**	23,149	24,780	24,765	23,853	23,532	22,807	20,541
Product prices								
Natural gas *($/mcf)*	**1.71**	2.82	3.70	1.63	1.65	2.25	1.89	1.62
Oil and NGL *($/bbl)*	**65.46**	62.07	37.08	73.81	72.66	65.86	62.34	50.29
Oil equivalent *($/boe)*	**45.04**	45.62	32.05	52.29	49.69	46.62	42.97	33.83
(000s, except per share amounts)								
Financial results								
Gross revenues	**98,741**	95,047	73,075	119,134	107,859	98,736	90,160	63,927
Cash provided by operating activities	**60,320**	48,089	49,137	62,644	64,606	60,285	50,056	35,237
Adjusted operating field netback (1)	**57,906**	57,503	38,346	68,579	61,005	58,545	57,583	34,774
Per share – basic	**0.26**	0.25	0.17	0.30	0.27	0.26	0.25	0.15
Per share – diluted	**0.25**	0.25	0.17	0.29	0.26	0.25	0.25	0.15
Net income (loss)	**16,472**	(4,826)	18,952	13,004	3,060	3,294	(12,525)	(6,742)
Per share – basic	**0.07**	(0.02)	0.08	0.06	0.01	0.01	(0.05)	(0.03)
Per share – diluted	**0.07**	(0.02)	0.08	0.06	0.01	0.01	(0.05)	(0.03)
Capital expenditures	**25,902**	71,243	25,798	78,149	52,674	69,630	35,516	74,063
Net acquisitions (dispositions)	**4,771**	1,074	(4,823)	–	(5,009)	2,790	1,713	2,962
Total assets	**1,336,323**	1,349,508	1,264,053	1,291,058	1,237,571	1,240,335	1,207,809	1,206,886
Net debt(1)	**195,892**	219,348	179,880	192,184	181,341	186,732	173,180	194,917
Bank debt	**186,912**	189,427	161,495	168,970	156,965	165,750	163,889	162,164
Decommissioning obligations	**218,950**	210,198	193,003	192,409	185,038	182,216	177,793	167,102

(1) Refer to definition of adjusted operating field netback 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 operating field netbacks 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 a net impairment charge in Q4 2018 in the amount of $58.0 million on its Cardium oil CGU due to falling gas prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit. In the same period, the Company also recorded an impairment reversal of $53.0 million on its Viking oil CGU. In Q4 2017, the Company recorded impairment charges on its heavy oil and certain natural gas related CGUs due to falling oil and natural gas prices in the amount of $17.0 million.

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 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, existence of active markets for the Company's products and the way in which management monitors operations.

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

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

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

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

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

Future Accounting Pronouncements

The Company did not identify any issued but not yet effective IFRSs that are expected to significantly impact the Company's financial statements.

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 interim 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%. 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 Q2 2019 financial results compared with what would have occurred had we not adopted the new accounting policy as follows:

- decreased production costs in the amount of $0.5 million;
- increased DD&A expenses in the amount of $0.6 million; and
- increased finance expenses in the amount of $0.3 million.

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 June 30, 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 June 30, 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, 2018, 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 Company’s compliance with the Curtailment Order;
- the impact of the Curtailment Order on Canadian crude prices and the Company’s drilling plans, production and guidance for the second half of 2019;
- the availability, size, terms, use and renewal of the Facility;
- the Company’s expectation that the five (5.0 net) Viking oil wells and four (3.5 net) Cardium oil wells will be brought on production in Q3/19;
- the performance of the Viking waterflood project, including oil recoveries and corporate decline rates;
- future use of the additional two (2.0 net) wells at Veteran;
- 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 primary focus areas for production growth;
- 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;
- Tamarack’s expectation to be fully self-funding in 2019;
- estimates for debt-adjusted production per share in Q4/19;
- 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 2019 and the first quarter of 2020;

- Tamarack's intent to use excess total adjusted operating field netbacks to purchase and cancel shares under the NCIB or to close additional accretive tuck-in acquisitions;
- future RSU settlements;
- Tamarack's ability to explore alternative gas markets and diversify its gas price exposure;
- Tamarack's plan to accelerate or reduce capital expenditures, redirect capital to purchase shares or pay down debt if commodity prices significantly fluctuate from the 2019 price assumptions;
- expectations for oil, NGL and natural gas pricing in 2019 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2019.

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

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production and transportation expenses and operating costs;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the ability to continue accumulating an inventory of Viking and Cardium locations that payout in 1.5 years or less at current commodity prices;
- the lifting of the Curtailment Order and the timing thereof;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax, royalty and regulatory regime.

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

- the material uncertainties and risks described under the headings "Unit Cost Calculation", "Non-IFRS Measures", "Critical Accounting Estimates", "Future Accounting Pronouncements", “Changes in Accounting Policies”, “Disclosure Controls and Internal Controls Over Financial Reporting”, “Business Risks”, “Financial Risks”, “Operational Risks” and “Regulatory Risks”;

- the material assumptions and observations described under the headings “Production”, “Petroleum and Natural Gas Sales”, "Royalties”, “Net Production and Transportation Expenses”, “Operating Netback”, “General and Administrative (“G&A”) Expenses”, “Stock-Based Compensation Expenses”, “Interest Expense”, “Depletion, Depreciation, Amortization and Accretion (“DDA&A”)”, “Income Taxes”, “Adjusted Operating Field Netback and Net Income (Loss)”, “Capital Expenditures (Including Exploration and Evaluation Expenditures)”, “Property Acquisitions”, “Share Capital”, “Liquidity and Capital Resources”, “Bank Debt”, “Guidance”, “Commitments” and “Selected Quarterly 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, 2018, which may be accessed on Tamarack’s SEDAR profile at www.sedar.com or on the Company's website at **www.tamarackvalley.ca**.

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

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)(thousands)

	June 30, 2019	December 31, 2018
Assets		
Current assets:		
Accounts receivable	$29,240	$21,211
Prepaid expenses and deposits	3,851	2,370
Fair value of financial instruments (note 4)	–	20,518
	33,091	44,099
Fair value of financial instruments (note 4)	–	1,533
Property, plant and equipment (note 6)	1,300,909	1,215,633
Exploration and evaluation assets (note 7)	2,323	2,788
	$1,336,323	$1,264,053
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$42,071	$41,966
Lease liabilities (note 9)	2,251	–
Fair value of financial instruments (note 4)	687	2,391
	45,009	44,357
Bank debt (note 13)	186,912	161,495
Lease liabilities (note 9)	10,964	–
Fair value of financial instruments (note 4)	211	–
Decommissioning obligations (note 8)	218,950	193,003
Deferred tax liability (note 15)	48,818	52,627
Shareholders' equity:		
Share capital (note 11)	845,348	848,249
Treasury shares (note 11)	(2,760)	(3,377)
Contributed surplus	38,080	34,554
Deficit	(55,209)	(66,855)
	825,459	812,571
Commitments (note 16)		
Subsequent event (note 4)		
	$1,336,323	$1,264,053

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income and Comprehensive Income
For the three and six months ended June 30, 2019 and 2018
(unaudited)(thousands, except per share amounts)

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Revenue:				
Oil and natural gas (note 5)	$98,741	$107,859	$193,788	$206,595
Processing income (expense) (note 5)	(215)	(274)	356	62
Royalties	(9,211)	(10,986)	(19,328)	(21,924)
Realized loss on financial instruments (note 4)	(3,461)	(7,293)	(4,400)	(8,548)
Unrealized gain (loss) on financial instruments (note 4)	1,251	(10,197)	(20,558)	(17,696)
	87,105	79,109	149,858	158,489
Expenses:				
Production	21,959	22,465	43,784	45,579
General and administration	3,118	3,374	6,078	6,753
Stock-based compensation (note 14)	2,399	1,461	3,719	2,975
Finance	3,897	3,477	7,316	6,325
Depletion, depreciation and amortization (note 6 and 7)	41,772	43,601	81,124	87,059
Gain on disposition of property, plant and equipment	–	–	–	(6)
	73,145	74,378	142,021	148,685
Income before taxes	13,960	4,731	7,837	9,804
Deferred income tax recovery (expense) (note 15)	2,512	(1,671)	3,809	(3,450)
Net income and comprehensive income	$16,472	$3,060	$11,646	$6,354
Net income per share (note 12):				
Basic	$ 0.07	$ 0.01	$ 0.05	$ 0.03
Diluted	$ 0.07	$ 0.01	$ 0.05	$ 0.03

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Shareholders' Equity
(unaudited)(thousands)

	Number of common shares net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2018	228,510	$850,357	$ –	$27,180	$(103,682)	$773,855
Issue of common shares	414	883	–	–	–	883
Purchase of common shares for cancellation	(1,081)	(4,126)	–	29	(324)	(4,421)
Purchase of common shares for RSU exercise	(970)	–	(3,999)	–	–	(3,999)
RSU exercise	400	–	1,647	(1,647)	–	–
Transfer on exercise of Options and RSUs	–	1,014	–	(1,014)	–	–
Stock-based compensation	–	–	–	4,256	–	4,256
Net income	–	–	–	–	6,354	6,354
Balance at June 30, 2018	227,273	$848,128	$(2,352)	$28,804	$(97,652)	$776,928
Balance at January 1, 2019	226,072	$848,249	$(3,377)	$34,554	$(66,855)	$812,571
Issue of common shares	15	41	–	–	–	41
Settlement of RSUs	163	595	–	(782)	–	(187)
Purchase of common shares for cancellation	(927)	(3,563)	–	1,339	–	(2,224)
Purchase of common shares for RSU exercise	(499)	–	(1,251)	–	–	(1,251)
RSU exercise	665	–	1,868	(1,868)	–	–
Transfer on exercise of Options	–	26	–	(26)	–	–
Stock-based compensation	–	–	–	4,863	–	4,863
Net income	–	–	–	–	11,646	11,646
Balance at June 30, 2019	225,489	$845,348	$(2,760)	$38,080	$(55,209)	$825,459

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and six months ended June 30, 2019 and 2018
(unaudited)(thousands)

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Cash provided by (used in):				
Operating:				
Net income	$16,472	$3,060	$11,646	$6,354
Depletion, depreciation and amortization (note 6 and 7)	41,772	43,601	81,124	87,059
Stock-based compensation (note 14)	2,399	1,461	3,719	2,975
Gain on disposition of property, plant and equipment	–	–	–	(6)
Accretion expense on decommissioning obligations (note 8)	1,026	1,015	2,171	2,022
Unrealized (gain) loss on financial instruments (note 4)	(1,251)	10,197	20,558	17,696
Deferred income tax (recovery) expense (note 15)	(2,512)	1,671	(3,809)	3,450
Abandonment expenditures (note 8)	(518)	(36)	(789)	(89)
Changes in non-cash working capital (note 10)	2,932	3,637	(6,211)	5,430
Cash provided by operating activities	60,320	64,606	108,409	124,891
Financing:				
Change in bank debt (note 13)	(2,515)	(8,785)	25,417	(6,924)
Proceeds from issuance of shares	41	507	41	883
Purchase of common shares for cancellation (note 11)	(1,541)	(4,421)	(2,224)	(4,421)
Purchase of common shares for RSU exercise (note 11)	(1,251)	(3,999)	(1,438)	(3,999)
Purchase of leased asset (note 9)	–	–	(22,328)	–
Repayment of lease liabilities (note 9)	(508)	–	(1,693)	–
Cash used in financing activities	(5,774)	(16,698)	(2,225)	(14,461)
Investing:				
Property, plant and equipment additions (note 6)	(25,870)	(51,059)	(97,106)	(120,466)
Exploration and evaluation additions (note 7)	(32)	(1,615)	(39)	(1,838)
Acquisitions	(4,771)	9	(5,845)	(2,781)
Proceeds from disposal of property, plant and equipment	–	5,000	–	5,000
Changes in non-cash working capital (note 10)	(23,873)	(243)	(3,194)	9,655
Cash used in investing activities	(54,546)	(47,908)	(106,184)	(110,430)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

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

2. Basis of preparation:

Statement of compliance:

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting" of International Financial Reporting Standards ("IFRS").

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2018 except as detailed in note 3. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2018.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on August 8, 2019.

3. Changes in accounting policies:

Adoption of IFRS 16 *Leases*:

Effective January 1, 2019, the Company adopted IFRS 16, "Leases" ("IFRS 16"). The Company has applied IFRS 16 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 Company's consolidated balance sheet and, consolidated statements of income and comprehensive income, changes in shareholders' equity and cash flows have not been restated. On adoption, management elected to use the following practical expedients permitted under IFRS 16:

- 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 right-of-use asset if the underlying asset is of a low dollar value (less than US$5 thousand); and

- the use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

The effect of initially applying the standard was a $37.2 million increase to lease liabilities, with a corresponding right-of-use-asset recorded. The right-of-use asset was measured at the amount equal to the lease liability on January 1, 2019 with no impact on opening deficit.

The preparation of the condensed consolidated interim financial statements in accordance with IFRS 16 requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 are listed below:

- Incremental borrowing rate: 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 term: Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

The following accounting policy came into effect on January 1, 2019:

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

- the contract involves the use of an identified asset; this may be specified explicitly or implicitly, and should be physically distinct or represent substantially all of the capacity of a physically distinct asset. If the supplier has a substantive substitution right, then the asset is not identified;
- the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- the Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used. In rare cases where the decision is predetermined, the Company has the right to direct the use of the asset if either:
    i. the Company has the right to operate the asset; or
    ii. the Company designed the asset in a way that predetermines how and for what purpose it will be used.

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

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

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

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

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

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

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

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

4. Risk management contracts:

It is the Company’s policy to economically hedge some oil and natural gas sales, foreign exchange and interest rates using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company’s production is usually sold using “spot” or near-term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet its expected sales requirements.

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 published forward price curves as at the balance sheet date, using the remaining contracted amounts and a risk-free interest rate (based on published government rates). The fair value of options and swaps are based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at fair value through profit or loss and therefore the carrying amount equals fair value.

At June 30, 2019, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	900 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $65.87	$935
Crude oil	200 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US $61.00	$113
Crude oil	3,105 bbls/day	July 1, 2019 – September 30, 2019	WTI put option	US $60.00	$1,268
Crude oil	2,990 bbls/day	October 1, 2019 – December 31, 2019	WTI put option	US $60.00	$1,926
Crude oil	4,000 bbls/day	July 1, 2019 – December 31, 2019	Edm par diff	US ($12.13)	($4,544)
Crude oil	3,000 bbls/day	August 1, 2019 – December 31, 2019	Edm par diff	US ($7.70)	($150)
Foreign exchange	5,750,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3065	$33
Foreign exchange	5,250,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.3140	($111)
Foreign exchange	1,000,000 US$/mth	January 1, 2020 – March 31, 2020	Exchange rate	Cdn $1.3405	($102)
Interest rate	25,000,000 US$/mth	July 1, 2019 – April 24, 2023	Fixed rate	1.90%	($201)
Interest rate	25,000,000 US$/mth	July 1, 2019 – June 14, 2023	Fixed rate	1.75%	($65)
					($898)

At June 30, 2019, Tamarack's commodity, foreign exchange and interest rate contracts were fair valued with a liability of $898 (December 31, 2018 - $19,660 asset) recorded on the balance sheet. The Company had an unrealized loss of $20,558 recorded in earnings for the six months ended June 30, 2019 (December 31, 2018 - $27,137 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 June 30, 2019, the Company held the following physical commodity contracts.

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	2,500 mmbtu/day	July 1, 2019 – October 31, 2019	AECO fixed price	Cdn $1.75
Natural gas	10,000 mmbtu/day	July 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	5,000 mmbtu/day	October 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.46
Natural gas	15,000 mmbtu/day	November 1, 2019 – November 30, 2019	AECO/Henry Hub differential	Index – US $1.31
Natural gas	15,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.41
Natural gas	15,000 mmbtu/day	December 1, 2019 – December 31, 2019	AECO/Henry Hub differential	Index – US $1.22

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

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

Gross Amounts ($ thousands)	**June 30, 2019**	December 31, 2018
Risk management contracts		
Current asset	**$ –**	$20,518
Long-term asset	**–**	1,533
Current liability	**(687)**	(2,391)
Long-term liability	**(211)**	–
Balance, end of the period	**$(898)**	$19,660

Since June 30, 2019, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US ($9.50)
Crude oil	2,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US ($7.95)

Since June 30, 2019, the Company has entered into the following physical contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	2,500 GJs/day	July 1, 2019 – September 30, 2019	AECO fixed price	Cdn $0.85
Natural gas	5,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub diff.	Index – US $0.95
Natural gas	5,000 mmbtu/day	April 1, 2020 – October 31, 2020	AECO/Henry Hub diff.	Index – US $1.35

5. Revenue:

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

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

The Company’s revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; and the Barons Sand oil play in the Penny area of southern Alberta. The Company’s customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at June 30, 2019, revenue was earned from customers, of which four customers account for $25.3 million of the accounts receivable at June 30, 2019.

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
Light oil	**$84,523**	$90,979	**$159,301**	$172,513
Heavy oil	**3,088**	3,363	**4,853**	4,581
Natural gas	**8,307**	7,857	**21,122**	18,367
Natural gas liquids	**2,823**	5,660	**8,512**	11,134
Oil and natural gas revenue	**$98,741**	$107,859	**$193,788**	$206,595
Processing income (expense)	**(215)**	(274)	**356**	62
Total revenue	**$98,526**	$107,585	**$194,144**	$206,657

Refer to note 4 for a listing of physical delivery contracts as at June 30, 2019.

Included in accounts receivable at June 30, 2019 was $28.1 million (December 31, 2018 - $13.8 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at June 30, 2019, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

6. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2018	$1,624,550	$1,368	$1,625,918
Property acquisition	2,847	–	2,847
Cash additions	223,102	217	223,319
Decommissioning costs	13,379	–	13,379
Stock-based compensation	3,598	–	3,598
Transfer from exploration and evaluation assets (note 7)	894	–	894
Disposals	(10,215)	–	(10,215)
Balance at December 31, 2018	1,858,155	1,585	1,859,740
Right-of-use assets (note 9)	37,236	–	37,236
Property acquisition	5,845	–	5,845
Cash additions	96,884	222	97,106
Decommissioning costs	24,565	–	24,565
Stock-based compensation	1,144	–	1,144
Transfer from exploration and evaluation assets (note 7)	37	–	37
Balance at June 30, 2019	$2,023,866	$1,807	$2,025,673
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2018	$462,969	$677	$463,646
Depletion and depreciation	176,255	243	176,498
Disposals	(1,037)	–	(1,037)
Impairment, net	5,000	–	5,000
Balance at December 31, 2018	643,187	920	644,107
Depletion and depreciation	80,545	112	80,657
Balance at June 30, 2019	$723,732	$1,032	$724,764

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2018	$1,214,968	$665	$1,215,633
At June 30, 2019	$1,300,134	$775	$1,300,909

The calculation of depletion at June 30, 2019 includes estimated future development costs of $650,224 (December 31, 2018 – $692,356) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $67,259 (December 31, 2018 – $57,813).

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

($ thousands)	Processing facilities
As at January 1, 2019	$37,236
Exercise of purchase option (note 9)	(23,014)
Depletion and depreciation	(1,128)
Balance at June 30, 2019	$13,094

7. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2018	$23,968
Additions	2,932
Transfer to property, plant and equipment (note 6)	(894)
Balance at December 31, 2018	26,006
Additions	39
Transfer to property, plant and equipment (note 6)	(37)
Balance at June 30, 2019	$26,008
Accumulated amortization and impairment:	
Balance at January 1, 2018	$22,140
Amortization	1,078
Balance at December 31, 2018	23,218
Amortization	467
Balance at June 30, 2019	$23,685

	Total
Carrying amounts:	
At December 31, 2018	$2,788
At June 30, 2019	$2,323

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

8. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $199.1 million at June 30, 2019 (December 31, 2018 – $191.3 million), which is expected to be incurred between 2019 and 2041. A risk-free rate of 1.7% (December 31, 2018 – 2.3%)

and an inflation rate of 2% (December 31, 2018 – 2%) is used to calculate the present value of the decommissioning obligations at June 30, 2019 as presented in the table below:

($ thousands)	**Six months ended June 30, 2019**	Year ended December 31, 2018
Balance, beginning of the period	**$193,003**	$177,793
Liabilities incurred	**7,768**	13,379
Change in estimates	**16,797**	–
Expenditures	**(789)**	(1,901)
Liabilities disposed	**–**	(374)
Accretion	**2,171**	4,106
Balance, end of the period	**$218,950**	$193,003

The change in estimate for the six months ended June 30, 2019 resulted from the decommissioning obligations being revalued using a risk-free rate of 1.7% as opposed to a risk-free rate of 2.3% used at December 31, 2018.

9. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities, surface leases, vehicles and field equipment. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the six months ended June 30, 2019 were between 4.5% and 8.8%, depending on the duration of the lease term. The following table summarizes lease liabilities at June 30, 2019:

($ thousands)	**Six months ended June 30, 2019**
Balance, beginning of the period	**$37,236**
Interest expense	**764**
Lease payments	**(2,457)**
Exercise of purchase option[(1)]	**(22,328)**
Balance, end of the period	**$13,215**
Current portion	**$2,251**
Long term portion	**$10,964**

(1) The Company exercised an option right to purchase a leased asset which is now included in property, plant and equipment.

Undiscounted cash outflows relating to the lease liabilities are:

($ thousands)	As at June 30, 2019
Less than 1 year	$3,071
Years 2 and 3	6,135
Years 4 and 5	5,366
Thereafter	4,742
Total	$19,314

10. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
Source/(use) of cash:				
Accounts receivable	**$11,858**	$9,479	**$(8,029)**	$8,260
Prepaid expenses and deposits	**(1,067)**	(51)	**(1,481)**	(338)
Accounts payable and accrued liabilities	**(31,732)**	(6,034)	**105**	7,163
	$(20,941)	$3,394	**$(9,405)**	$15,085
Related to operating activities	**$2,932**	$3,637	**$(6,211)**	$5,430
Related to investing activities	**$(23,873)**	$(243)	**$(3,194)**	$9,655

The following are included in cash flows from operating activities:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
Interest paid in cash on bank debt	**$2,038**	$2,113	**$3,745**	$3,951
Bank renewal fees	**580**	349	**636**	352
Interest paid on lease liabilities	**253**	–	**764**	–

11. Shareholders' equity:

a) Share capital:

At June 30, 2019 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

b) Restricted share units:

During the six months ended June 30, 2019 the Company settled 231,000 restricted share units ("RSUs") by issuing 163,000 Common Shares and a payment of $0.2 million for withholding tax on behalf of the employee in exchange for the remaining balance of 68,000 RSUs.

c) Normal course issuer bid:

On April 4, 2018, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares between April 6, 2018 and April 5, 2019.

On April 4, 2019, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a new NCIB. Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares between April 8, 2019 and April 7, 2020. During the six months ended June 30, 2019, the Company purchased and cancelled 926,900 Common Shares at an average price of $2.40 per Common Share, for a total purchase price of $2.2 million.

d) Treasury shares:

As at June 30, 2019, 1,027,694 Common Shares were classified as treasury shares to be used for the future settlements of RSUs exercised.

12. Income per share:

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except per share amounts)	**2019**	2018	**2019**	2018
Net income	**$16,472**	$3,060	**$11,646**	$6,354
Weighted average shares - basic	**225,989**	228,040	**226,166**	228,329
Weighted average shares - diluted	**231,152**	232,310	**231,287**	232,255
Net income per share-basic	**$ 0.07**	$ 0.01	**$ 0.05**	$ 0.03
Net income per share-diluted	**$ 0.07**	$ 0.01	**$ 0.05**	$ 0.03

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For both the three and six months ended June 30, 2019, 8.6 million Common Shares issuable upon the exercise and/or settlement of stock options ("Options"), RSUs, performance share units ("PSUs") and TAC Preferred Shares (as defined below) were included in the diluted weighted average number of Common Shares outstanding. For the three and six months ended June 30, 2018, 10.7 million and 8.4 million, respectively, Common Shares issuable upon the exercise and/or settlement of Options, RSUs, PSUs and TAC Preferred Shares were included in the diluted weighted average numbers of Common Shares outstanding.

13. Bank debt:

The Company 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, totaling $350 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 in one year from that date.

In November 2018, an accordion feature was added to the lending agreement which allows Tamarack to increase the revolving credit facility to $370 million for a total Facility of $400 million, upon exercise and syndicate approval. The accordion feature bears no fees, including standby, until exercised. As at June 30, 2019, the accordion has not been exercised.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt-to-cash-flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and LIBOR Based Loans ("LIBOR") will vary based on a BA/LIBOR pricing grid from a low of the banks' posted rates plus 1.5% to a high of the banks' posted rates plus 3.5%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 0.5% to a high of the banks' prime rates plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.3375% to a high of 0.7875% on the undrawn portion of the Facility. The lending vehicles Tamarack employs from time to time will vary based on capital needs and current market rates. As at June 30, 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 banks' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for November 2019.

At June 30, 2019, the Company had utilized the Facility in the amount of $186.9 million. The interest rate applicable to the drawn amounts as of this date was 3.44%. As at June 30, 2019, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility.

There are no financial covenants governing the Facility. Non-financial covenants include reporting requirements, permitted indebtedness, permitted hedging and other standard business operating covenants.

14. Share-based payments:

(a) Preferred share plan:

There are 1,021,974 (December 31, 2018 – 1,086,974) preferred shares of Tamarack Acquisition Corp. (the "TAC Preferred Shares") issued and outstanding. At June 30, 2019, the TAC Preferred Shares were fully vested and exchangeable into 982,667 (December 31, 2018 – 1,045,168) Common Shares at an exchange price of $3.12 per Common Share.

Under the terms of the Company's preferred share plan, a cashless settlement alternative is available, whereby holders of TAC Preferred Shares can either (i) elect to receive Common Shares by delivering cash to the Company in the amount of the TAC Preferred Shares, or (ii) elect to receive a number of Common Shares equivalent to the market value of the TAC Preferred Shares in excess of the TAC Preferred Shares at the exchange price of $3.12 per Common Share. For the six months ended June 30, 2019 no TAC Preferred Shares were exchanged and 65,000 TAC Preferred Shares were forfeited.

(b) Options:

Pursuant to the Company's stock option plan (the "Stock Option Plan") and the Company's performance and restricted share unit plan (the "PRSU Plan"), the Company may grant up to an aggregate of 15.8 million Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at June 30, 2019, there is an aggregate of 13.4 million Options, RSUs and PSUs issued and outstanding.

Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 390,000 Options granted during the six months ended June 30, 2019.

The fair value of each Option granted during the six months ended June 30, 2019 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

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

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

	Number of Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2018	4,556	$3.79
Granted	195	2.62
Exercised	(1,682)	3.23
Expired	(124)	5.68
Outstanding, December 31, 2018	2,945	$3.95
Granted	390	2.57
Exercised	(15)	2.75
Expired	(709)	5.02
Outstanding, June 30, 2019	**2,611**	**$3.46**

The range of exercise prices of the Options outstanding and exercisable at June 30, 2019 is as follows:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 2.57 – 3.00	1,271	$2.67	2.9	722	$2.72
$ 3.01 – 5.00	1,121	$3.70	2.0	820	$3.80
$ 5.01 – 6.82	219	$6.82	0.1	219	$6.82
$ 2.57 – 6.82	**2,611**	**$3.46**	**2.3**	**1,761**	**$3.73**

(c) RSUs:

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.5 million RSUs granted during the six months ended June 30, 2019.

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

The following table summarizes information about the RSU:

	Number of RSU (thousands)
Outstanding, January 1, 2018	5,818
Granted	2,378
Exercised	(709)
Forfeited	(80)
Outstanding, December 31, 2018	7,407
Granted	2,501
Exercised	(896)
Forfeited	(357)
Outstanding, June 30, 2019	**8,655**
Exercisable, June 30, 2019	**3,310**

(d) PSUs:

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 1.1 million PSUs granted during the six months ended June 30, 2019.

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

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2018	–
Awarded	983
Outstanding, December 31, 2018	983
Awarded	1,147
Forfeited	(37)
Outstanding, June 30, 2019	**2,093**
Earned, June 30, 2019	**246**

Exercisable, June 30, 2019	**–**

15. Income taxes:

For the three and six months ended June 30, 2019, the deferred income tax recovery includes $6.5 million attributable to reductions in the Alberta corporate income tax rate 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 reduce the rate by an additional 1% on January 1 for each of 2020, 2021, and 2022, bringing the provincial tax rate to 8%.

16. 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 June 30, 2019:

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Office lease(1)	271	263	–	–	–	–	–
Take or pay commitments(2)	1,103	2,256	2,294	2,340	2,396	–	–
Gas transportation(3)	365	229	76	–	–	–	–
Total	1,739	2,748	2,370	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

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

David MacKenzie(1)(2)

Jeff Boyce(1)(2)

Noralee Bradley(3)(4)

John Leach(1)(3)

Ian Currie(2)(4)

Rob Spitzer(3)(4)

Brian Schmidt

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

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliot LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Contact Information

Tamarack Valley Energy Ltd.
Fifth Avenue Place – East Tower
600, 425 – 1st Street SW
Calgary, AB T2P 3L8
Telephone: 403 263 4440
Fax: 403 263 5551
www.tamarackvalley.ca