MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months ended March 31, 2021 and 2020. This MD&A is dated and based on information available as at May 4, 2021 and should be read in conjunction with the unaudited condensed consolidated interim financial statements ("financial statements") and the notes thereto for the three months ended March 31, 2021 and 2020 and the audited consolidated financial statements for the year ended December 31, 2020. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2020, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The financial statements have been prepared in accordance with International Accounting Standards 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 18. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

M&A Driving Enhanced Resilience

On March 25, 2021, Tamarack closed two separate agreements to acquire assets in the Provost and Nipisi areas of Alberta (the "Acquisitions"). The Acquisitions included approximately 2,800 boe/d of low decline (~16%) oil weighted assets under waterflood and added approximately 38,400 net acres in the Clearwater oil play of Alberta (the "Assets") for a net cash purchase price of approximately $121 million. These acquisitions furthered our strategy of building a balanced portfolio focused on enhancing the resilience of our free adjusted funds flow (see "Non-IFRS Measures") through the addition of acreage and inventory in the highly economic and profitable Clearwater oil play, along with low decline waterflood assets. The acquisitions were financed through a combination of debt, a $68.2 million bought deal financing (30.3 million commons shares at $2.25 per share) in March 2021, along with a Gross Overriding Royalty ("GORR") disposition on the newly acquired Greater Nipisi Clearwater and Slave Point lands for proceeds of approximately $13.5 million.

Subsequent to the end of the quarter, Tamarack entered into a definitive agreement to acquire Anegada Oil Corp. ("Anegada") – a privately held, pure play, Charlie Lake light oil producer – for total net consideration of $494 million (the "Anegada Acquisition"), after deducting the proceeds from a newly created 2% GORR on the acquired assets. The total net consideration consists of $247.5 million in cash and debt (net of GORR), subject to adjustment, and approximately 105.3 million Common Shares of Tamarack at a deemed price of $2.34 per share. Tamarack's credit syndicate has provided commitments to increase the available capacity under the Company's credit facility to $600 million and extend the revolving period to May 31, 2022, concurrent with the close of the Anegada Acquisition. As announced on

April 28th, 2021, the Company has received written consent from shareholders holding a majority of the issued and outstanding shares to approve the Acquisition and as such will not be holding a special meeting on the Acquisition. Furthermore, Tamarack and Anegada have made the necessary filings with the Competition Bureau under the Competition Act (Canada) with respect to the Acquisition and, as the Competition Bureau is treating the Acquisition as a "noncomplex" transaction, it is anticipated that the required approval will be received on or about May 4, 2021. Following receipt of the Competition Act approval, the parties intend to work expeditiously towards closing the Acquisition and anticipate closing will occur on or about May 31, 2021.

Q1 2021 Financial and Operating Highlights

- Achieved quarterly production volumes of 23,938 boe/d in Q1/21, representing a 2% increase compared to the same period in 2020.
- Generated adjusted funds flow (see “Non-IFRS Measures”) of $41.2 million in Q1/21 ($0.16 per share basic and diluted).
- Invested $48.7 million in exploration and development (“E&D”) capital expenditures, excluding acquisitions, during the first quarter of 2021, which contributed to the drilling of 44 (42.3 net) wells, comprised of 22 (22.0 net) Viking oil wells, 16 (15.5 net) Clearwater oil wells, two (0.8 net) Falher gas wells and four (4.0 net) water source and injector wells. The Company continued to direct significant capital to our Viking waterflood program which represented approximately 34% of the total E&D capital expenditures.
- Executed a successful Clearwater winter capital program with the drilling of 16 (15.5 net) wells, with the faster execution of drilling operations enabling three wells from our planned second quarter to be accelerated to the first. The per well drilling, completion, equipping and tie-in costs averaged $1.06 million versus the $1.1 million per well forecast. The winter drilling program exit production volumes in excess of 4,000 bbl/d exceeded previous expectations.

Managing Through the Novel Coronavirus (COVID-19)

The first quarter of 2021 was characterized by an improvement in crude oil and natural gas prices, however the novel coronavirus (COVID-19) pandemic continues to impact the global economy. The path to a full economic recovery is dependent on the impacts of the spread of the variants, vaccine roll-outs, changes to social and travel restrictions and business resuming to regular operations. In addition to this, the global benchmark crude oil prices will be dependent on demand recovery and the return of OPEC and Non-OPEC supply and as such, the potential for volatility continues to persist.

Tamarack continues to proactively respond to the safety and financial challenges of the COVID-19 pandemic. The Company has improved our flexibility and responsiveness by establishing capabilities and procedures for remote working and opening our corporate head office on a limited and intermittent basis during the first quarter. Tamarack remains committed to ensuring the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate, going above and beyond both Provincial and Federal government protocols.

Sustainability

Tamarack continues to be committed to advancing our environmental, social and governance ("ESG") practices as outlined in our inaugural Sustainability Report published in the third quarter of 2020. This report provides details on the Company's approach to sustainability, including our commitment to greenhouse gas emissions management and to continued Indigenous and community partnerships in the areas where Tamarack operates. In addition, the report highlights specific, measurable goals and targets related to key focus areas set by the Company.

Production

Year-over-Year	Three months ended March 31,		
	2021	2020	% change
Production			
Light oil (bbls/d)	**10,120**	12,867	(21)
Heavy oil (bbls/d)	**2,654**	180	1,374
Natural gas liquids (bbls/d)	**2,420**	1,665	45
Natural gas (mcf/d)	**52,466**	52,912	(1)
Total (boe/d)	**23,938**	23,531	2
Percentage of oil and NGL	**63%**	63%	–

Average production for Q1/21 increased 2% compared to the same period in 2020 due to the West Central Acquisition that closed on July 9, 2020, the Clearwater Acquisition that closed on December 21, 2020 and an additional 740 boe/d from Veteran and 546 boe/d from Clearwater development programs, partially offset by expected declines of existing base production. The Company's oil and NGL weighting for Q1/21 is consistent with the same period in 2020.

Petroleum and Natural Gas Sales

Year-over-Year	Three months ended March 31,		
	2021	2020	% change
Revenue ($ thousands)			
Oil and NGL	**$77,823**	$58,117	34
Natural gas	**14,873**	7,755	92
Total	**$92,696**	$65,872	41
Average realized price:			
Light oil ($/bbl)	**64.01**	46.42	38
Heavy oil ($/bbl)	**48.00**	49.76	(4)
Natural gas liquids ($/bbl)	**37.17**	19.44	91
Combined average oil and NGL ($/boe)	**56.91**	43.41	31
Natural gas ($/mcf)	**3.15**	1.61	96
Revenue ($/boe)	**43.03**	30.76	40
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**57.80**	46.08	25
Edmonton Par (Cdn$/bbl)	**66.54**	51.34	30
Hardisty Heavy (Cdn$/bbl)	**61.62**	40.41	52
NYMEX monthly settlement (US$/mmbtu)	**2.69**	1.95	38
AECO daily index (Cdn$/mcf)	**3.12**	2.03	54
AECO monthly index (Cdn$/mcf)	**2.92**	2.13	37

Revenue per boe from oil, natural gas and NGL sales for Q1/21 increased by 40%, compared to the same period in 2020, due to improved and stabilized commodity prices realized in 2021 compared to the depressed prices realized in 2020 as a result of the emergence and declaration of the COVID-19 pandemic.

The WTI benchmark price for Q1/21 averaged US$57.80/bbl, a 25% increase over the WTI benchmark for the same period in 2020 of US$46.08/bbl. In addition, the WTI/Edmonton Par light oil differential improved to an average of US$5.23/bbl and the WTI/WCS heavy oil differential improved to an average of US$9.11/bbl, compared to US$7.56/bbl and US$15.73/bbl respectively in Q1/20. These factors combined to bolster Tamarack's realized light oil wellhead price for the three months ended March 31, 2021 to $64.01/bbl from $46.42/bbl in the same quarter of 2020. Conversely, Tamarack's realized heavy oil wellhead price decreased slightly to $48.00/bbl in Q1/21 from $49.76/bbl in Q1/20 due to the increased contributions from the Clearwater heavy oil production which are sold on a standard heavy price, while small historical volumes received a premium due to favourable marketing arrangements.

The first quarter was characterized by greater stability in WTI pricing as a result of continued OPEC+ production management combined with economic improvement indicators in large economies, including the US and China, partially offset by new waves of COVID-19 and variant cases in many areas including Canada and India. Continued uncertainty about near term oil demand and the long-term economic impacts of the global COVID-19 pandemic introduce near term pricing risk; however, pricing improvements, combined with increasing global demand and decreasing oil product inventories, are positive indicators of a less volatile pricing environment for 2021. Tamarack will continue to prudently manage commodity price risk through hedging in order to effectively manage cash flow risk, while ensuring sufficient opportunity to capture near term commodity pricing upside.

Realized NGL prices increased 91% to $37.17/bbl in Q1/21 from $19.44/bbl in Q1/20. The increase is due largely to the improved WTI price year-over-year, which is the basis for condensate and butane pricing, in addition to more favourable terms for the 2020-2021 contract year compared to 2019-2020 contract year. While global oil and liquids inventories continue to decrease, Alberta natural gas liquid inventory remains high creating uncertainty in the NGL market pricing outlook. As a result of this uncertainty and the upcoming 2021-2022 contract renegotiations, Tamarack expects some volatility in pricing through 2021.

Tamarack's realized natural gas price increased 96% to $3.15/mcf in Q1/21 from $1.61/mcf in Q1/20. The AECO daily benchmark price increased 54% to $3.12/mcf in Q1/21 from $2.03/mcf in Q1/20 while the NYMEX monthly settlement price increased 38% to US$2.69/mmbtu in Q1/21 from US$1.95/mmbtu in Q1/20. The increase in the Company's Q1/21 realized price and the benchmark prices compared to same quarter in the previous year was primarily due to improved market conditions, winter heating demands due to extreme cold across North America in the quarter and lower supply as a result of decreased drilling activity in 2020. The increase in Tamarack's realized price deviates slightly from the increases seen in the two indices due to the Company's diversification strategy that balances pricing exposure over multiple markets. Tamarack will also continue to manage commodity price risk through financial and physical hedges.

The Company continues to employ multiple third-party gas sales contracts featuring various end dates until 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate individual market volatility risk. The Company will carefully evaluate diversification strategies for natural gas contracts beyond 2022. During the first quarter of 2021, some of Tamarack's natural gas production was priced at alternate markets to AECO, including Malin, Chicago, Michigan City Gate, Dawn and Waddington. Pricing in these markets is contracted as daily index pricing less transportation tolls or as fixed basis fees.

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 March 31, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables:

		Q2 2021	Q3 2021	Q4 2021	Q1 2022
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	**Volume (bbls/d)**	**2,250**	**250**	**–**	**–**
	Average Price (US$/bbl)	$46.55	$50.00	–	–
WTI fixed price swap (with swaption)[1]	**Volume (bbls/d)**	**2,000**	**500**	**–**	**–**
	Average Price (US$/bbl)	$47.20	$50.00	–	–
WTI two-way collar (with swaption)[2]	**Volume (bbls/d)**	**1,500**	**–**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	–	–	–
	Average Sold Call (US$/bbl)	$51.17	–	–	–
WTI two-way collar	**Volume (bbls/d)**	**750**	**1,000**	**1,500**	–
	Average Bought Put (US$/bbl)	$41.67	$40.00	$43.33	–
	Average Sold Call (US$/bbl)	$51.43	$50.50	$53.67	–
	Average Premium (US$/bbl)	$1.67	$2.00	$1.33	–
WTI three-way collar	**Volume (bbls/d)**	**–**	**1,000**	**1,000**	**–**
	Average Bought Put (US$/bbl)	–	$40.00	$40.00	–
	Average Sold Call (US$/bbl)	–	$60.00	$60.00	–
	Average Sold Put (US$/bbl)	–	$32.00	$32.00	–
	Average Premium (US$/bbl)	–	$2.00	$2.00	–
WTI put	**Volume (bbls/d)**	**–**	**–**	**250**	**–**
	Average Bought Put (US$/bbl)	–	–	$52.27	–
	Average Premium (US$/bbl)	–	–	$2.27	–
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	**Volume (bbls/d)**	**4,250**	**3,250**	**3,250**	**–**
	Average Price (US$/bbl)	($5.70)	($5.68)	($5.68)	–
WCS to WTI fixed price differential swap	**Volume (bbls/d)**	**500**	**1,500**	**–**	**–**
	Average Price (US$/bbl)	($12.00)	($11.88)	–	–

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

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

		Q2 2021	Q3 2021	Q4 2021	Q1 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	**Amount ($US/month)**	**$1,000,000**	–	–	–
	Average Forward Rate (CAD/USD)	1.4140	–	–	–
CAD/USD average rate forward (with extension option)(1)	**Amount ($US/month)**	**$500,000**	–	–	–
	Average Forward Rate (CAD/USD)	1.3843	–	–	–
CAD/USD collar style swap (with extension option)(2)	**Amount ($US/month)**	**$500,000**	**$500,000**	**$500,000**	–
	Floor Forward Rate (CAD/USD)	1.3000	1.3000	1.3000	–
	Ceiling Forward Rate (CAD/USD)	1.3615	1.3615	1.3615	–

(1) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3843 (H2/21).
(2) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3615 (2022).

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

At March 31, 2021, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of $26.0 million (December 31, 2020 - $10.2 million net liability) recorded on the balance sheet. The Company recorded an unrealized loss of $15.9 million and a realized loss of $8.2 million in earnings for the three months ended March 31, 2021, compared to an unrealized gain of $51.2 million and a realized gain of $10.9 million during the same period in 2020. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are credit grade banking institutions or large purchasers of commodities in the normal course of business. All counterparties have been assessed for credit worthiness.

Subsequent to March 31, 2021, the Company has entered into the following financial contracts:

		Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives			
WTI fixed price swap[1]	***Volume (bbls/d)***	**500**	**500**
	Average Price (US$/bbl)	$55.98	$55.98
WTI two-way collar	***Volume (bbls/d)***	**500**	**500**
	Average Bought Put (US$/bbl)	$50.00	$50.00
	Average Sold Call (US$/bbl)	$80.75	$80.75
	Average Premium (US$/bbl)	$2.00	$2.00
WTI put	***Volume (bbls/d)***	**2,250**	**2,250**
	Average Bought Put (US$/bbl)	$49.98	$49.98
	Average Premium (US$/bbl)	$1.87	$1.87
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**1,500**	**1,500**
	Average Price (US$/bbl)	($4.70)	($4.70)
		Summer 21	**Winter 21-22**
Gas Derivatives			
AECO fixed price swap	***Quantity (GJ/d)***	**5,000**	**5,000**
	Average Price (CAD$/GJ)	$2.77	$2.95
		May 21 - Oct 21	**Nov 21 - Apr 22**
CAD/USD Foreign Exchange Derivatives			
CAD/USD target average rate redemption forward [2]	***Amount ($US/month)***	**$500,000**	**$500,000**
	Average Forward Rate (CAD/USD)	1.2825	1.2700
	Target Value (bps)	0.03	0.03

(1) Includes a bought call on the same volume at $61.50USD/bbl.

(2) Swap terminates at the earlier of: a) when 3 basis points (bps) of value are achieved by the Company and b) April 25, 2022.

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 March 31, 2021, the Company held the following physical commodity contracts:

		Summer 21	Winter 21-22	Summer 22
Natural Gas Physical Contracts				
AECO 5A	**Quantity (GJ/d)**	**20,000**	**15,000**	**–**
	Average Price (CAD$/GJ)	$2.43	$2.80	–
Malin	**Quantity (DTH/d)**	**4,000**	**–**	**–**
	Average Price (US$/DTH)	$2.83	–	–

Subsequent to March 31, 2021, the Company has not entered into any physical commodity contracts.

Royalties

Year-over-Year	Three months ended March 31,		
	2021	2020	% change
Royalty expenses ($ thousands)	**$11,566**	$8,082	43
$/boe	**5.37**	3.77	42
Percent of sales (%)	**12**	12	–

Royalties as a percentage of revenue for the first quarter of 2021 were similar to the same period in 2020. The Company expects royalty rates as a percentage of revenue to remain in the 11% to 12% range for 2021 based on current forecast commodity pricing levels. On an absolute basis, royalty expense was higher in Q1/21 compared to same period in 2020 due to an increase in commodity prices and production.

Net Production Expenses

Year-over-Year	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Production expenses	**$21,478**	$19,541	10
Less: processing income	**738**	411	80
Total net production expenses	**$20,740**	$19,130	8
Total ($/boe)	**$9.63**	$8.93	8

For the three months March 31, 2021, per unit net production expenses (see “Non-IFRS Measures’) were higher compared to the same period in 2020. This resulted from the West Central Acquisition properties having higher per unit net production expenses compared to the corporate average before the acquisition, along with an increase in workovers. Gross and net production expenses were higher compared to the same period in 2020 due to higher per unit net production expenses and higher production.

Transportation Expense

Year-over-Year	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Transportation expense - gas	**$1,699**	$1,193	42
Transportation expense - oil	**1,609**	1,045	54
Total transportation expense	**$3,308**	$2,238	48
Total ($/boe)	**$1.54**	$1.05	47

For the three months March 31, 2021, per unit transportation expense was higher compared to the same period in 2020. This increase was a result of the Clearwater assets acquired late in 2020 along with the 2021 Clearwater development program, requiring oil to be trucked to sales points. Transportation expense was higher compared to the same period in 2020 due to higher per unit transportation expense and higher production.

Operating Netback

Year-over-Year			
	Three months ended March 31,		
($/boe)	**2021**	2020	% change
Average realized sales	**$43.03**	$30.76	40
Royalty expenses	**(5.37)**	(3.77)	42
Net production expenses	**(9.63)**	(8.93)	8
Transportation expense	**(1.54)**	(1.05)	47
Operating field netback	**26.49**	17.01	56
Realized commodity hedging gain (loss)	**(3.81)**	5.10	(175)
Operating netback	**$22.68**	$22.11	3

For the three months ended March 31, 2021, operating netbacks were higher than the same period in 2020 primarily due to higher commodity prices realized in Q1/21, partially offset by higher net production expenses, higher transportation expense, higher royalties and a realized commodity hedging loss in Q1/21.

General and Administrative ("G&A") Expenses

Year-over-Year			
	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Gross costs	**$5,120**	$4,311	19
Capitalized costs and recoveries	**(1,262)**	(1,193)	6
General and administrative costs	**$3,858**	$3,118	24
Total ($/boe)	**$1.79**	$1.46	23

Gross and net G&A costs and net G&A costs on a per boe basis for Q1/21 were higher compared to the same period in 2020, due to increased staffing levels related to the recently completed Acquisitions and the final determination of the annual incentive plan which is paid out in the first quarter of each year.

Stock-Based Compensation Expense

Year-over-Year			
	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Gross costs	**$3,320**	$1,279	160
Capitalized costs	**(1,670)**	(329)	408
Expensed stock-based compensation	**$1,650**	$950	74
Total ($/boe)	**$0.77**	$0.44	75

Stock-based compensation expense related to Options, RSUs and PSUs for the three months ended March 31, 2021 was higher compared to the same period in 2020 due to grants being issued at a higher share price along with performance targets being exceeded resulting in additional PSUs being granted.

During the three months ended March 31, 2021, the Company issued 0.6 million Options (at a weighted average exercise price of $2.25 per share), 1.6 million RSUs and 2.3 million PSUs compared to 0.6 million Options (at a weighted average exercise price of $1.13 per share), 1.9 million RSUs and 1.7 million PSUs during the same period in 2020.

Finance Expense

Year-over-Year			
	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Interest on bank debt	**$2,611**	$1,950	34
Fees associated with credit facility renewal	**271**	–	–
Interest on lease liabilities	**184**	224	(18)
Unrealized loss on foreign exchange	**1,267**	4,398	(71)
Unrealized gain on cross-currency swap	**(1,251)**	(4,349)	(71)
Accretion of decommissioning obligations	**820**	640	28
Total finance expense	**$3,902**	$2,863	36
Total ($/boe)	**$1.81**	$1.34	35
Average drawings on bank debt	**$229,850**	$194,173	18

Total finance expense for the three months ended March 31, 2021 was higher than the same period in 2020 as a result of higher average drawings on bank debt, fees associated with the redetermination of the credit facility with respect to the Acquisitions and increased borrowing rates related to the bank renewal in June 2020.

Depletion, Depreciation and Amortization ("DD&A")

Year-over-Year	Three months ended March 31,		
($ thousands, except per boe)	**2021**	2020	% change
Depletion and depreciation	**$30,383**	$39,391	(23)
Amortization of undeveloped leases	**161**	126	28
Total	**$30,544**	$39,517	(23)
Depletion and depreciation ($/boe)	**$14.10**	$18.40	(23)
Amortization ($/boe)	**0.07**	0.06	17
Total ($/boe)	**$14.17**	$18.46	(23)

For the three months ended March 31, 2020, DD&A expense per boe was lower relative to the same period in 2020. The decrease was due to the completion of the Company's December 31, 2020 reserve report which resulted in an increase in Tamarack's overall proved and probable oil and natural gas reserve base following the 2020 drilling program and the West Central Acquisition and Clearwater Acquisition; and an impairment charge taken in both Q1/20 and Q4/20 which reduced the net book value of assets to be depleted. On an absolute basis, DD&A expense was lower for the three months ended March 31, 2021 due to reduced DD&A expense per boe, partially offset by higher production.

At March 31, 2021 there were no indicators of impairment or reversal of impairment identified on any of the Company's CGU's within property, plant and equipment and no impairment test was performed, as compared with the comparative period ended March 31, 2020 when the Company identified indicators of impairment and recorded an impairment charge of $381.0 million.

Income Taxes

The Company did not incur any cash tax expense for the three months ended March 31, 2021 and does not expect to pay any cash tax until 2024 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months ended March 31, 2021, a deferred income tax expense of $0.4 million was recognized compared to a deferred income tax recovery of $77.6 million for the same period in 2020.

Adjusted Funds Flow and Net Loss

Year-over-Year	Three months ended March 31,		
($ thousands, except per share)	**2021**	2020	% change
Cash flow from operating activities	**$38,436**	$46,359	(17)
Abandonment expenditures	**589**	1,785	(67)
Changes in non-cash working capital	**2,211**	(6,099)	(136)
Adjusted funds flow	**$41,236**	$42,045	(2)
Per share - basic	**$0.16**	$0.19	(16)
Per share - diluted	**$0.16**	$0.19	(16)
Net loss	**$(166)**	$(251,321)	(100)
Per share - basic	**$(0.00)**	$(1.13)	(100)
Per share - diluted	**$(0.00)**	$(1.13)	(100)

Adjusted funds flow and cash flow from operating activities for the three months ended March 31, 2021 were lower compared to the same period in 2020. This was primarily due to a realized hedging loss in Q1/21 compared to a realized hedging gain in Q1/20 and higher royalty expense, partially offset by a 41% increase in revenue.

The Company recorded a net loss of $0.2 million ($0.00 per share basic and diluted) during Q1/21 compared to a net loss of $251.3 million ($1.13 per share basic and diluted) in Q1/20. This was primarily due to a 41% increase in revenue, lower DD&A expense, a gain on disposition of property, plant and equipment and an impairment charge taken in Q1/20, partially offset by a deferred income tax recovery in Q1/20 and both a realized and unrealized hedging loss in Q1/21 compared to gains in Q1/20.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

Year-over-Year	Three months ended March 31,		
($ thousands)	**2021**	2020	% change
Land	**$1,855**	$1,882	(1)
Geological and geophysical	**218**	16	1,263
Drilling and completion	**35,431**	57,221	(38)
Equipment and facilities	**10,048**	13,723	(27)
Capitalized G&A	**976**	976	–
Office equipment	**176**	55	220
Total capital expenditures	**$48,704**	$73,873	(34)

During the first quarter of 2021, the Company drilled, completed and equipped twenty-two (22.0 net) Viking oil wells, fifteen (14.5 net) Clearwater oil wells and four (4.0 net) water source and injector wells. The Company also drilled and completed two (0.8 net) Falher gas wells and drilled one (1.0 net) Clearwater oil well.

For the three months ended March 31, 2021 Drilling Summary		
	Gross	Net
Viking	22.0	22.0
Clearwater	16.0	15.5
Falher	2.0	0.8
Water source and injectors	4.0	4.0
	44.0	42.3

As at March 31, 2021, the Company's net undeveloped land totaled 667,785 acres.

Acquisitions and Dispositions

On March 25, 2021, the Company completed two concurrent acquisitions of certain oil and gas properties located in the Provost and Nipisi areas of Alberta from two separate unrelated parties.

The first acquisition, included assets in both the Provost and Nipisi areas (the "Acquisition 1") was completed for total cash consideration of $102.6 million. There were $0.7 million of transaction costs expensed in earnings. The acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of March 25, 2021. Assets acquired in this transaction will be included in the Viking oil cash-generating unit ("CGU") and the Clearwater oil CGU. Assets held for sale relate to the GORR disposition on the Acquisition 1 Nipisi area assets. The determination of the purchase price, based on management's preliminary estimate of fair values, is as follows:

($ thousands)		**Amount**
Net assets acquired:		
Oil and natural gas interests	$	103,859
Assets held for sale		3,571
Decommissioning obligations		(4,820)
Net assets acquired	**$**	**102,610**
Purchase consideration:		
Cash	$	102,610
Total purchase consideration	**$**	**102,610**

The above amounts are estimates, which were made by management at the time of preparation of the financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized through the final statement of adjustments.

The fair value of property, plant and equipment has been estimated with reference to an internally prepared reserves evaluation for the acquired properties. The estimated proved and probable oil and natural gas reserve and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk free-rate of 8%.

The second acquisition in the Nipisi area (the "Acquisition 2") was completed for total cash consideration of $34.4 million including $0.9 million of capitalized transaction costs and the issuance of 4.9 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $2.09 per share, the total consideration was approximately $44.6 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction will be included in the Clearwater oil CGU. Assets held for sale relate to the GORR disposition on the Acquisition 2 Nipisi area assets.

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

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	42,232
Assets held for sale		2,409
Decommissioning obligations		(65)
Net assets acquired	**$**	**44,576**
Purchase consideration:		
Cash consideration	$	34,358
Share consideration (4,888,889 common shares)		10,218
Total purchase consideration	**$**	**44,576**

Share Capital

(thousands)	**March 31, 2021**	May 4, 2021	December 31, 2020
Common shares outstanding	**298,327**	301,770	262,776
Common shares held in treasury	**388**	1,090	747
Options outstanding	**2,497**	2,407	1,904
RSUs outstanding	**6,704**	6,482	5,365
PSUs outstanding	**5,729**	5,586	3,564

At March 31, 2021, Tamarack Acquisition Corp. had 740,307 preferred shares ("TAC Preferred Shares") issued and outstanding (December 31, 2020 – 740,307). The TAC Preferred Shares were fully vested and exchangeable into 711,834 Common Shares (December 31, 2020 – 711,834) of Tamarack at an exchange price of $3.12 per Common Share.

On March 25, 2021, the Company issued 30,303,000 Common Shares at $2.25 per common share for total gross proceeds of $68.2 million and the Company issued 4,888,889 Common Shares in connection with Acquisition 2.

Subsequent to the quarter end, the over-allotment option granted on the March 25, 2021 share issuance was exercised and the Company issued 3,030,300 Common Shares at $2.25 per common share for total gross proceeds of $6.8 million.

Liquidity and Capital Resources

($ thousands)	**March 31, 2021**	December 31, 2020
Working capital deficiency	**$15,365**	$8,454
Bank debt	**270,810**	210,857
Net debt	**286,175**	219,311
Quarterly adjusted funds flow	**$41,236**	$28,894
Annualized factor	**4**	4
Annualized adjusted funds flow	**164,944**	115,576
Net debt to annualized adjusted funds flow	**1.7x**	1.9x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency (surplus) (see "Non-IFRS Measures"), totaled $286.2 million as at March 31, 2021. This compares to the Company's net debt of $227.2 million in Q1/20 and $219.3 million in Q4/20. Tamarack's Q1/21 net debt to annualized adjusted funds flow ratio (see "Non-IFRS Measures") was 1.7 times as the Company carried out the Acquisitions in March 2021. The Company's forecasted plan is to reduce the ratio to 1.5x by the end of Q4/21.

The Company's $185.7 million investment in capital additions and acquisitions during Q1/21 was funded by net proceeds of a share issuance of $65.0 million, the sale of royalty interests of $13.9 million, Tamarack's adjusted funds flow (see "Non-IFRS Measures") of $41.2 million and an increase of net debt of $65.6 million.

Despite the improvement in commodity prices during the first quarter, Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by managing capital spending levels as appropriate to respond to changes in realized commodity prices and through the systematic hedging program using both financial derivatives and physical delivery contracts to mitigate risk.

At times, Management believes the Company's prevailing share price does not adequately reflect the underlying value of Tamarack's assets. As such, we may utilize an NCIB program through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company has the option to purchase our Common Shares for cancellation, thereby reducing the total number of shares outstanding. The Company suspended the NCIB program during the second quarter of 2020, however we may reinstate the program in the future.

Bank Debt

Tamarack currently has available a revolving credit facility in the amount of $295 million and an operating facility of $30 million (collectively, the "Facility") with a syndicate of lenders. Concurrent with the close of the Acquisitions on March 25, 2021, the Facility increased from a total of $275 million to a total of $325 million, of which $270.8 million was drawn as of March 31, 2021 (December 31, 2020 – $210.9 million). The Facility will be subject to its next extension by November 30, 2021. If not extended by November 30, 2021, will cease to revolve and all outstanding balances will become repayable one year from that date.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on both a total amount drawn and a net debt-to-cash-flow ratio as defined in the Facility. The interest rate will vary depending on: the lending vehicle employed; the total loan value drawn; 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 3.00% to a high of the banks' posted rates plus 5.00%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 2.00% to a high of the banks' prime rates plus 4.00%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.25% 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 March 31, 2021, 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, 2021.

There are no financial covenants governing the Facility.

Subsequent to March 31, 2021, the Company entered into a definitive agreement to acquire Anegada Oil Corp., with an expected acquisition closing date on or before May 31, 2021. Tamarack's syndicate of lenders has provided commitments to increase the available capacity under the Company's credit facilities to $600 million and extend the revolving period to May 31, 2022, concurrent with the close of the Anegada Acquisition.

Commitments

The following table summarizes the Company's commitments as at March 31, 2021:

($ thousands)	2021	2022	2023	2024	2025+
Bank debt(1)	–	270,810	–	–	–
Lease(2)	163	229	229	229	172
Take or pay commitments(3)	2,976	4,023	3,894	–	–
Gas transportation(4)	2,203	1,955	640	143	7
Capital commitments(5)	25,000	65,000	50,000	–	–
Total	30,342	342,017	54,763	372	179

(1) If not extended by November 30, 2021, the Facility will cease to revolve and all outstanding balances will become repayable November 30, 2022.

(2) Relates to the variable operating costs, which are a non-lease component of the Company's head office sublease and sublease expansion. The head office sublease and sublease expansion commence at dates of April 1, 2021 and June 1, 2021, respectively and expire on September 30, 2025. At sublease and sublease expansion commencement the Company will recognize estimated lease liabilities and related right-of-use assets of $1.7 million and $0.5 million, respectively.

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

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

(5) Commitment of $140.0 million of capital to further develop the GORR Nipisi/Clearwater lands prior to December 31, 2023.

Contingency

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of $56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of $1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged Tamarack has breached the

Company's fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

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

Unit Cost Calculation

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

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
DTH	dekatherm
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
WCS	Western Canadian Select
WTI	West Texas Intermediate

Non–IFRS Measures

This document contains the terms "adjusted funds flow", "net production expenses", "operating netback", "operating field netback", "net debt", "net debt to annualized adjusted funds flow ratio" and "free adjusted funds flow" which are non-IFRS financial measures. The Company uses these measures to help evaluate Tamarack's performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

(a) **Adjusted Funds Flow -** Adjusted funds flow is calculated by taking cash-flow from operating activities and adding back changes in non-cash working capital and expenditures on decommissioning obligations since Tamarack believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating loss per share. The calculation of the Company's adjusted funds flows is summarized starting on page 13 in the section titled "Adjusted Funds Flow and Net Loss".

(b) **Net Production Expenses, Operating Netback and Operating Field Netback** - Management uses certain industry benchmarks, such as net production expenses, operating netback and operating field netback, to analyze financial and operating performance. Net production expenses are determined by deducting processing income primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. Under IFRS this source of funds is required to be reported as revenue. Where the Company has excess capacity at one of its facilities, it will process third party volumes as a means to reduce the cost of operating/owning the facility, and as such third party processing revenue is netted against production expenses in the MD&A. 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, net production expenses and transportation expense and can also be calculated on a per boe basis. Operating field netback equals total petroleum and natural gas sales, less royalties, net production expenses and transportation expense. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures to evaluate Tamarack's 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 10 in the section titled "Operating Netback".

(c) **Net Debt and Working Capital Deficiency (Surplus)-** Tamarack closely monitors our 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 our capital structure. The Company uses net debt (bank debt plus working capital surplus or deficiency, including the fair value of cross-currency swaps and excluding the current portion of the fair value of financial instruments, decommissioning obligations 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:

($ thousands)	**March 31, 2021**	December 31, 2020
Accounts payable and accrued liabilities	**$61,766**	$38,903
Cross currency swap liability	**346**	1,597
Accounts receivable	**(44,506)**	(30,781)
Prepaid expenses and deposits	**(2,241)**	(1,265)
Working capital deficiency	**15,365**	8,454
Bank debt	**270,810**	210,857
Net debt	**$286,175**	$219,311

(d) **Net Debt to Annualized Adjusted Funds Flow** – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of the Company and our ability to pay off debt and take on new debt, if necessary, using the most recent quarter's results.

(e) **Free Adjusted Funds Flow –** Management uses certain industry benchmarks, such as free adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions, Management believes that free adjusted funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

Selected Quarterly Information

Three months ended	**Mar. 31, 2021**	Dec. 31, 2020	Sep. 30, 2020	Jun. 30, 2020	Mar. 31, 2020	Dec. 31, 2019	Sep. 30, 2019	Jun. 30, 2019
Sales volumes								
Natural gas *(mcf/d)*	**52,466**	53,738	53,420	49,610	52,912	54,462	55,224	53,451
Oil and NGL *(bbls/d)*	**15,194**	13,093	12,630	12,729	14,712	15,782	14,967	15,181
Average boe/d *(6:1)*	**23,938**	22,049	21,533	20,997	23,531	24,859	24,171	24,090
Product prices								
Natural gas *($/mcf)*	**3.15**	2.46	1.61	1.37	1.61	2.26	1.54	1.71
Oil and NGL *($/bbl)*	**56.91**	43.22	42.69	23.40	43.41	59.51	59.38	65.46
Oil equivalent *($/boe)*	**43.03**	31.67	29.02	17.42	30.76	42.72	40.28	45.04
(000s, except per share amounts)								
Financial results								
Gross revenues	**92,696**	64,238	57,491	33,295	65,872	97,699	89,579	98,741
Cash provided by operating activities	**38,436**	23,859	26,965	28,107	46,359	54,623	42,199	60,320
Adjusted funds flow (1)	**41,236**	28,894	30,837	20,972	42,045	54,742	49,283	57,906
Per share – basic	**0.16**	0.13	0.14	0.09	0.19	0.25	0.22	0.26
Per share – diluted	**0.16**	0.13	0.14	0.09	0.19	0.25	0.22	0.25
Net income (loss)	**(166)**	(18,220)	(5,776)	(36,067)	(251,321)	(50,546)	(111)	16,472
Per share – basic	**(0.00)**	(0.08)	(0.03)	(0.16)	(1.13)	(0.23)	0.00	0.07
Per share – diluted	**(0.00)**	(0.08)	(0.03)	(0.16)	(1.13)	(0.23)	0.00	0.07
Capital expenditures	**48,704**	13,088	10,364	6,218	73,873	22,954	58,867	25,902
Acquisitions(1)	**147,187**	94,684	4,127	–	–	250	3,847	4,771
Dispositions	**(13,884)**	(15,525)	–	–	–	–	–	–
Total assets	**1,199,743**	1,027,600	963,220	935,892	984,045	1,247,119	1,369,918	1,336,323
Net debt(2)	**286,175**	219,311	199,561	213,066	227,151	189,481	213,140	195,892
Bank debt	**270,810**	210,857	198,994	206,467	209,423	192,907	198,971	186,912
Decommissioning obligations	**242,692**	245,437	241,047	198,485	186,816	184,846	222,684	218,950

(1) Includes cash and non-cash common share considerations.
(2) Refer to definition of adjusted funds flow and net debt under "Non-IFRS Measures".

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

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flows and earnings.
- The volatility in decommissioning obligations due to fluctuations in discount rates and acquisitions.

- 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.
- On March 25, 2021, Tamarack closed two separate agreements to acquire assets in the Provost and Nipisi areas of Alberta. The assets include approximately 2,800 boe/d of low decline (~16%) oil weighted assets under waterflood, along with added approximately 38,400 net acres in the Clearwater oil play of Alberta for a total purchase price of approximately $147.2 million.
- On December 21, 2020, the Company completed two acquisitions of certain oil properties located in the Greater Nipisi area of Alberta. The assets include approximately 2,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.
- On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets include approximately 2,500 boe/d (52% oil and NGL) of production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.
- The Company recorded an impairment charge in Q4/20 in the amount of $18.0 million on our Penny oil CGU due to a reduction in the current quantities of recoverable proved and probable oil and natural gas reserves.
- The Company recorded an impairment charge in Q1/20 in the amount of $381.0 million on our CGUs due to decreased current and forecasted oil and natural gas prices. The impairment charge was recorded in the following CGUs: the Viking oil CGU was impaired $235.0 million, the Cardium oil CGU was impaired $137.0 million, the Penny oil CGU was impaired $7.0 million and the minor gas CGU was impaired $2.0 million.
- The Company recorded an impairment charge in Q4/19 in the amount of $68.0 million on its Cardium oil CGU due to decreased current and forecasted natural gas prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit.

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 and probable reserves.

(b) **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 oil and natural gas reserves. Changes in estimated proved and probable oil and natural gas 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 exploration and evaluation ("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 inflows. The allocation of the Company's assets into CGUs requires significant judgment with respect to the use of shared infrastructure, geographic proximity, existence of active markets for the Company's products, the way in which management monitors operations and materiality.

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

The Company assesses PP&E for impairment or impairment reversal 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 or impairment reversal exists, the Company performs an impairment test related to the specific CGU. The determination of the estimated recoverable amount of a CGU is based on estimates of proved and probable oil and natural gas reserves and the related cash flows. By their nature, these estimates of proved and probable oil and natural gas reserves and the related cash flows are subject to uncertainty including significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs and forecasted future development costs and the impact on the financial statements of future periods could be material.

(c) **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.

(d) **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.

(e) **Business combinations –** The application of the Company's accounting policy for business combinations requires management to make certain judgements on a case-by-case basis as to the determination of the accounting method of an acquisition to determine if the assets acquired meet the definition of a business combination or an asset acquisition. In a business combination, management makes estimates of the acquisition-date fair value of assets acquired and liabilities assumed which includes assessing the estimated fair value of petroleum and natural gas properties (included in property, plant and equipment) derived from estimated recoverable quantities of proved and probable oil and natural gas reserves and the related cash flows being acquired.

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 our annual filings, interim filings or other reports filed or submitted 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.

The Company established procedures for remote working and opened the corporate head office on a limited and intermittent basis during the period. Working from home required certain processes and controls that were previously done or documented manually to be completed and retained in electronic form. The changes required by the current environment resulted in no significant changes in the Company's internal controls during the period ended March 31, 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. As a result, the Company's DCP and ICFR were effective as at March 31, 2021.

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 forecasts. 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 additional information on the risks relating to Tamarack's business, see "Risk Factors" in Tamarack's Annual Information Form for the year ended December 31, 2020, which can be found on SEDAR at www.sedar.com.

(a) **Impact of the COVID-19 Pandemic**

Tamarack's business, financial condition and results of operations could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which it has operations, suppliers, customers or employees, including the global outbreak of COVID-19. The COVID-19 pandemic, given its severity, scale, duration and rapid evolution, and actions that may be taken by governmental authorities in response thereto, has resulted, and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions and restrictions on gatherings greater than a certain number of individuals, shelter in place declarations and quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to Tamarack's financial performance, including oil, natural gas and NGL, and also increases the risk that storage for oil could reach capacity in certain geographic locations in which Tamarack operates. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, has resulted in, and may continue to result in, the Company shutting-in production, which could adversely impact the Company's business, financial condition and results of operations.

The Company is also subject to risks relating to the health and safety of its personnel, as well as the potential for a slowdown or temporary suspension of its operations in locations impacted by an outbreak, increased labour and fuel costs and regulatory changes. Tamarack has implemented health and safety measures at Tamarack's facilities and offices to limit the risk of transmission of COVID-19. Additionally, Tamarack follows posted health guidelines, as and when posted, to protect the health of its employees and decrease the potential impact of serious illness, including COVID-19, on its operations. However, should an employee of, or visitor to, any of Tamarack's facilities or offices become infected with COVID-19, it could place Tamarack's entire workforce at risk, which could result in the suspension of operations at one or more of Tamarack's facilities. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact Tamarack's production for a sustained period of time, which could adversely impact its business, financial condition and results of operations.

In addition, the disruption and volatility in global capital markets that has resulted, and may continue to result, from the COVID-19 pandemic could increase the Company's cost of capital and adversely affect the Company's ability to access the capital markets on a timely basis, or at all.

The COVID-19 pandemic continues to rapidly evolve and the full impact on the Company's business, financial condition and results of operations, as well as the Company's future capital expenditures and other discretionary items, will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence, including: the geographic spread of the virus; the duration and extent of the pandemic, the spread of new variant strains of the virus, further actions that may be taken by governmental authorities, including in respect of travel restrictions and business disruptions; the severity of the disease; and the effectiveness of actions taken to contain the virus and treat the disease, including access to effective vaccines. To the extent that the COVID-19 pandemic continues to adversely affects Tamarack's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in this MD&A and Tamarack's Annual Information Form for the year ended December 31, 2020.

(b) Continued Volatility in Commodity and Petroleum Products Prices

Market events and conditions, including global excess oil, natural gas and petroleum product supply as a result of actions taken by OPEC and non-OPEC oil and gas exporting countries to set and maintain increased production levels and influence oil prices and decreased global demand due to the COVID-19 pandemic caused significant weakness and volatility in commodity and petroleum product prices during the first half of 2020 and corresponding reductions in industry capital and operating budgets. With the rapid spread of the COVID-19 pandemic and additional crude oil supply expected to come on-stream over the near term, the price of oil and other petroleum products deteriorated significantly in the first half of 2020 and remained under pressure with increased volatility throughout 2020 and is expected to continue to exhibit increased volatility. The overall result of these events and conditions could lead to a prolonged period of volatile prices for oil and other petroleum products. Similar to the risks and uncertainties outlined above under "Impact of the COVID-19 Pandemic", this could result in reduced utilization and/or the suspension of operations at certain of the Company's facilities, buyers of the Company's products declaring force majeure and disruptions of pipeline and other transportation systems for the Company's products, which would further negatively impact Tamarack's production, and could adversely impact Tamarack's business, financial condition and results of operations.

These events and conditions in the first half of 2020 also caused significant decreases in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada. The overall impact of these current market conditions and the lack of confidence in the Canadian crude oil and natural gas industry could materially and adversely affect Tamarack's business, prospects, financial condition, results of operations and cash flows.

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. The Company’s exploration and production activities emit greenhouse gasses ("GHG") which may require Tamarack to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on Tamarack’s business, financial condition, results of operations and prospects. 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”, “strive” and similar expressions or the negative of such terms or other comparable terminology. 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:

- Tamarack’s business strategy, objectives, strength and focus, including with respect to acquisitions;
- the completion of the Anegada Acquisition and the terms and timing thereof;
- the intentions of management and the Company;
- the COVID-19 pandemic, the Company’s and governmental authorities’ current and planned responses thereto and the impact thereof on, without limitation, the Company in particular and the oil and gas industry in general;

- applications and grants under the Canada Emergency Wage Subsidy (“**CEWS**”), Alberta Site Rehabilitation Program (“**SRP**”) and Saskatchewan Accelerated Site Closure Program (“**ASCP**”) programs;
- the Company’s commitment to the practices outlined in the Environmental, Social and Governance Sustainability Report published in Q3 2020;
- expectations relating to future realized commodity prices, volatile commodity prices and oil price differentials and the effects thereof, including with respect to revenue and earnings;
- Tamarack’s financial and physical hedging program;
- Tamarack’s commitment to maintaining financial flexibility;
- Tamarack being well positioned from a liquidity standpoint;
- committed capital spending to develop the GORR lands and timing thereof;
- uncertainty regarding the full impact of COVID-19 on global economies, oil demand and commodity prices;
- uncertainty regarding the duration and extent of oil demand destruction resulting from the COVID-19 pandemic;
- Tamarack’s exposure to diversified gas markets and the effects thereof;
- expectation relating to risk mitigation and realized price improvements from exposure to diversified gas markets;
- Tamarack’s third-party gas sales contracts that provide diversification of the Company’s natural gas price exposure and mitigate individual market volatility risk;
- Tamarack’s use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack’s use of commodity, foreign exchange and interest rate contracts and risk management thereof;
- expectations as to royalty rates as a percentage of revenue;
- expectations relating to the timing for paying cash tax;
- Tamarack’s strategy for preserving balance sheet strength;
- deferred tax assets, including in respect of deferred income tax;
- future RSU and PSU settlements;
- the availability, size, terms, use and renewal of the Company’s facility, including an increase to available capacity in connection with the Anegada Acquisition;
- contractual obligations and commitments; and
- estimates used to calculate decommissioning obligations and depletion of PP&E.

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 expenses and transportation expense;
- estimated proved and probable oil and natural gas reserves;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;

- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the acquisitions and the related drilling programs;
- the ability to explore and realize benefits from exposure to diversified gas markets;
- drilling results, including field production rates and decline rates;
- the performance of the waterflood projects;
- 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;
- the continuation of the current tax, royalty and regulatory regime;
- the volatility in commodity prices and oil price differentials and the resulting effect on Tamarack's revenue, cash provided by operating activities, adjusted funds flows and earnings;
- the ability to adjust capital spending relative to commodity prices and use financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- the ability to maintain financial flexibility;
- the ability to renew the Facility on acceptable terms; and
- Tamarack's ability to execute its plans in response to the COVID-19 pandemic.

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", "Changes in Accounting Standards", "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 "M&A Driving Enhanced Resiliency of the Business", "Q1 2021 Financial and Operating Highlights", "Managing Through the Novel Coronavirus (COVID-19)", "Sustainability", "Production", "Petroleum and Natural Gas Sales", "Royalties", "Net Production Expenses", "Transportation Expense", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expense", "Finance Expense", "Depletion, Depreciation and Amortization ("DD&A")", "Income Taxes", "Adjusted Funds Flow and Net Loss", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Acquisitions and Dispositions", "Share Capital", "Liquidity and Capital Resources", "Bank Debt", "Commitments", "Contingency" and "Selected Quarterly Information";
- the COVID-19 pandemic and the impact on the Company's business, financial condition and results of operations;

- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production and including continued weakness and volatility in commodity prices and petroleum product prices;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand;
- 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 proved and probable 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;
- credit worthiness of counterparties to commodity, foreign exchange and interest rate contracts;
- 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;
- the ability to renew the Facility on acceptable terms and the impact thereof;
- changes in tax, royalty and environmental legislation and any government policy; and
- any legal proceedings, the results thereof and the impact on the Company's business, financial condition and results of operations.

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, 2020, 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, production, free adjusted funds flow, net debt, net debt to annualized adjusted funds flow, corporate decline rates, royalty rates 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 approved by management 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.

References in this MD&A to IP30 and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Tamarack.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets

(thousands)

	March 31, 2021	December 31, 2020
Assets		
Current assets:		
Accounts receivable	**$44,506**	$30,781
Prepaid expenses and deposits	**2,241**	1,265
Fair value of financial instruments (note 4)	**–**	981
	46,747	33,027
Property, plant and equipment (note 6 and 7)	**1,101,578**	943,430
Exploration and evaluation assets (note 8)	**1,436**	1,460
Deferred tax asset	**49,982**	49,683
	$1,199,743	$1,027,600
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$61,766**	$38,903
Lease liabilities (note 10)	**2,549**	2,484
Decommissioning obligations (note 9)	**7,411**	6,000
Cross-currency swap (note 14)	**346**	1,597
Fair value of financial instruments (note 4)	**25,577**	9,942
	97,649	58,926
Bank debt (note 14)	**270,810**	210,857
Lease liabilities (note 10)	**6,949**	7,670
Fair value of financial instruments (note 4)	**471**	1,192
Decommissioning obligations (note 9)	**235,281**	239,437
	611,160	518,082
Shareholders' equity:		
Share capital (note 12)	**952,035**	876,124
Treasury shares (note 12)	**(339)**	(703)
Contributed surplus	**54,303**	51,347
Deficit	**(417,416)**	(417,250)
	588,583	509,518
Subsequent events (note 4, 12, 14 and 18)		
Commitments (note 16)		
Contingency (note 17)		
	$1,199,743	$1,027,600

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Loss and Comprehensive Loss
For the three months ended March 31, 2021 and 2020
(thousands, except per share amounts)

	2021	2020
Revenue:		
Oil and natural gas (note 5)	**$92,696**	$65,872
Processing income (note 5)	**738**	411
Royalties	**(11,566)**	(8,082)
Net revenue	**81,868**	58,201
Financial instrument contracts:		
Realized gain (loss) on financial instruments (note 4)	**(8,206)**	10,915
Unrealized gain (loss) on financial instruments (note 4)	**(15,895)**	51,192
Net revenue and gains (losses) on financial instruments	**57,767**	120,308
Expenses:		
Production	**21,478**	19,541
Transportation	**3,308**	2,238
General and administration	**3,858**	3,118
Transaction costs (note 7)	**716**	–
Stock-based compensation (note 15)	**1,650**	950
Finance	**3,902**	2,863
Depletion, depreciation and amortization (note 6 and 8)	**30,544**	39,517
Gain on disposition of property, plant and equipment (note 6)	**(7,843)**	–
Site rehabilitation program grant (note 9)	**(124)**	–
Impairment of property, plant and equipment (note 6)	**–**	381,000
	57,489	449,227
Income (loss) before taxes	**278**	(328,919)
Deferred income tax recovery (expense)	**(444)**	77,598
Net loss and comprehensive loss	**$(166)**	$(251,321)
Net loss per share (note 13):		
Basic	**$(0.00)**	$(1.13)
Diluted	**$(0.00)**	$(1.13)

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

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

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2020	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Purchase of common shares for cancellation	(664)	(2,551)	–	1,262	–	(1,289)
Purchase of common shares for RSU exercise	(1,841)	–	(2,182)	–	–	(2,182)
RSU exercise	566	–	1,112	(1,112)	–	–
Stock-based compensation	–	–	–	1,279	–	1,279
Net loss	–	–	–	–	(251,321)	(251,321)
Balance at March 31, 2020	220,854	$830,248	$(2,039)	$49,240	$(357,187)	$520,262
Balance at January 1, 2021	262,776	$876,124	$(703)	$51,347	$(417,250)	$509,518
Issue of common shares	35,193	78,400	–	–	–	78,400
RSU and PSU exercise	358	–	364	(364)	–	–
Share issue costs, net of tax of $743	–	(2,489)	–	–	–	(2,489)
Stock-based compensation	–	–	–	3,320	–	3,320
Net loss	–	–	–	–	(166)	(166)
Balance at March 31, 2021	298,327	$952,035	$(339)	$54,303	$(417,416)	$588,583

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three months ended March 31, 2021 and 2020
(thousands)

	2021	2020
Cash provided by (used in):		
Operating:		
Net loss	**$(166)**	$(251,321)
Depletion, depreciation and amortization (note 6 and 8)	**30,544**	39,517
Stock-based compensation (note 15)	**1,650**	950
Gain on disposition of property, plant and equipment (note 6)	**(7,843)**	–
Site rehabilitation program grant (note 9)	**(124)**	–
Accretion expense on decommissioning obligations (note 9)	**820**	640
Unrealized loss (gain) on financial instruments (note 4)	**15,895**	(51,192)
Unrealized loss on foreign exchange	**1,267**	4,398
Unrealized gain on cross-currency swap (note 14)	**(1,251)**	(4,349)
Impairment of property, plant and equipment (note 6)	**–**	381,000
Deferred income tax expense (recovery)	**444**	(77,598)
Abandonment expenditures (note 9)	**(589)**	(1,785)
Changes in non-cash working capital (note 11)	**(2,211)**	6,099
Cash provided by operating activities	**38,436**	46,359
Financing:		
Change in bank debt (note 14)	**58,686**	12,118
Net proceeds from issuance of shares (note 12)	**64,950**	–
Purchase of common shares for cancellation	**–**	(1,289)
Purchase of common shares for RSU exercises	**–**	(2,182)
Repayment of lease liabilities (note 10)	**(656)**	(537)
Changes in non-cash working capital (note 11)	**1,675**	–
Cash provided by financing activities	**124,655**	8,110
Investing:		
Property, plant and equipment additions (note 6)	**(48,349)**	(73,857)
Exploration and evaluation additions (note 8)	**(355)**	(16)
Acquisitions (note 7)	**(136,969)**	–
Proceeds from disposal of property, plant and equipment (note 6)	**13,884**	–
Changes in non-cash working capital (note 11)	**8,698**	19,404
Cash used in investing activities	**(163,091)**	(54,469)
Change in cash and cash equivalents	**–**	–
Cash and cash equivalents, beginning of period	**–**	–
Cash and cash equivalents, end of period	**$ –**	$ –

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 3300, 308 – 4th Avenue S.W., Calgary, Alberta, T2P 0H7.

2. Basis of preparation:

(a) 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, 2020. 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, 2020. Certain prior period balances were reclassified to conform to current period presentation.

The consolidated financial statements were authorized for issue by the Board of Directors on May 4, 2021.

(b) Estimates and judgments:

The preparation of the condensed consolidated interim financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the condensed consolidated interim financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the interim financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. The significant estimates and judgments made by management in the preparation of these condensed consolidated interim financial statements were consistent with those applied to the annual consolidated financial statements as at and for the year ended December 31, 2020.

3. COVID-19:

The first quarter of 2021 was characterized by an improvement in crude oil and natural gas prices, however the novel coronavirus (COVID-19) pandemic continues to impact the global economy. The path to a full economic recovery is dependent on the impacts of the spread of the variants, vaccine roll-outs, changes to social and travel restrictions and business resuming to regular operations. In addition to this, the global benchmark crude oil prices will be dependent on demand recovery and the return of OPEC and Non-OPEC supply and as such the potential for volatility continues to persist.

Tamarack continues to proactively respond to the safety and financial challenges of the COVID-19 pandemic. The Company has improved our flexibility and responsiveness by establishing capabilities and procedures for remote working and opening our corporate head office on a limited and intermittent basis during the first quarter. Tamarack remains committed to ensuring the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate, going above and beyond both Provincial and Federal government protocols.

4. Risk management contracts:

It is the Company's policy to economically hedge some oil and natural gas sales, foreign exchange rates 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. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are credit grade banking institutions or large purchasers of commodities in the normal course of business. All counterparties have been assessed for credit worthiness.

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.

(thousands, except per share and per unit amounts)

At March 31, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

		Q2 2021	Q3 2021	Q4 2021	Q1 2022
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	**Volume (bbls/d)**	**2,250**	**250**	**–**	**–**
	Average Price (US$/bbl)	$46.55	$50.00	–	–
WTI fixed price swap (with swaption)(1)	**Volume (bbls/d)**	**2,000**	**500**	**–**	**–**
	Average Price (US$/bbl)	$47.20	$50.00	–	–
WTI two-way collar (with swaption)(2)	**Volume (bbls/d)**	**1,500**	**–**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	–	–	–
	Average Sold Call (US$/bbl)	$51.17	–	–	–
WTI two-way collar	**Volume (bbls/d)**	**750**	**1,000**	**1,500**	–
	Average Bought Put (US$/bbl)	$41.67	$40.00	$43.33	–
	Average Sold Call (US$/bbl)	$51.43	$50.50	$53.67	–
	Average Premium (US$/bbl)	$1.67	$2.00	$1.33	–
WTI three-way collar	**Volume (bbls/d)**	**–**	**1,000**	**1,000**	**–**
	Average Bought Put (US$/bbl)	–	$40.00	$40.00	–
	Average Sold Call (US$/bbl)	–	$60.00	$60.00	–
	Average Sold Put (US$/bbl)	–	$32.00	$32.00	–
	Average Premium (US$/bbl)	–	$2.00	$2.00	–
WTI put	**Volume (bbls/d)**	**–**	**–**	**250**	**–**
	Average Bought Put (US$/bbl)	–	–	$52.27	–
	Average Premium (US$/bbl)	–	–	$2.27	–
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	**Volume (bbls/d)**	**4,250**	**3,250**	**3,250**	**–**
	Average Price (US$/bbl)	($5.70)	($5.68)	($5.68)	–
WCS to WTI fixed price differential swap	**Volume (bbls/d)**	**500**	**1,500**	**–**	**–**
	Average Price (US$/bbl)	($12.00)	($11.88)	–	–

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

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

(thousands, except per share and per unit amounts)

		Q2 2021	Q3 2021	Q4 2021	Q1 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	**Amount ($US/month)**	**$1,000,000**	–	–	–
	Average Forward Rate (CAD/USD)	1.4140	–	–	–
CAD/USD average rate forward (with extension option)(1)	**Amount ($US/month)**	**$500,000**	–	–	–
	Average Forward Rate (CAD/USD)	1.3843	–	–	–
CAD/USD collar style swap (with extension option)(2)	**Amount ($US/month)**	**$500,000**	**$500,000**	**$500,000**	–
	Floor Forward Rate (CAD/USD)	1.3000	1.3000	1.3000	–
	Ceiling Forward Rate (CAD/USD)	1.3615	1.3615	1.3615	–

(1) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3843 (H2/21).
(2) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3615 (2022).

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

At March 31, 2021, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability of $26,048 (December 31, 2020 - $10,153 net liability) recorded on the balance sheet. The Company recorded an unrealized loss of $15,895 and a realized loss of $8,206 in earnings for the three months ended March 31, 2021 (March 31, 2020 - $51,192 unrealized gain and $10,915 realized 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 March 31, 2021, the Company held the following physical commodity contracts:

		Summer 21	Winter 21-22	Summer 22
Natural Gas Physical Contracts				
AECO 5A	**Quantity (GJ/d)**	**20,000**	**15,000**	**–**
	Average Price (CAD$/GJ)	$2.43	$2.80	–
Malin	**Quantity (DTH/d)**	**4,000**	**–**	**–**
	Average Price (US$/DTH)	$2.83	–	–

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)	March 31, 2021	December 31, 2020
Risk management contracts		
Current asset	**$ –**	$981
Current liability	**(25,577)**	(9,942)
Long-term liability	**(471)**	(1,192)
Balance, end of the period	**$(26,048)**	$(10,153)

Subsequent to March 31, 2021, the Company has entered into the following derivative contracts:

		Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives			
WTI fixed price swap[1]	***Volume (bbls/d)***	**500**	**500**
	Average Price (US$/bbl)	$55.98	$55.98
WTI two-way collar	***Volume (bbls/d)***	**500**	**500**
	Average Bought Put (US$/bbl)	$50.00	$50.00
	Average Sold Call (US$/bbl)	$80.75	$80.75
	Average Premium (US$/bbl)	$2.00	$2.00
WTI put	***Volume (bbls/d)***	**2,250**	**2,250**
	Average Bought Put (US$/bbl)	$49.98	$49.98
	Average Premium (US$/bbl)	$1.87	$1.87
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**1,500**	**1,500**
	Average Price (US$/bbl)	($4.70)	($4.70)
		Summer 21	**Winter 21-22**
Gas Derivatives			
AECO fixed price swap	***Quantity (GJ/d)***	**5,000**	**5,000**
	Average Price (CAD$/GJ)	$2.77	$2.95
		May 21 - Oct 21	**Nov 21 - Apr 22**
CAD/USD Foreign Exchange Derivatives			
CAD/USD target average rate redemption forward [2]	***Amount ($US/month)***	**$500,000**	**$500,000**
	Average Forward Rate (CAD/USD)	1.2825	1.2700
	Target Value (bps)	0.03	0.03

(1) Includes a bought call on the same volume at $61.50USD/bbl.

(2) Swap terminates at the earlier of: a) when 3 basis points (bps) of value are achieved by the Company and b) April 25, 2022.

Subsequent to March 31, 2021, the Company has not entered into any physical contracts.

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 NGL to the contract counterparty.

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

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; the Clearwater oil play in the Nipisi area of northern Alberta; 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 selling volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at March 31, 2021, five customers accounted for $27.2 million of the accounts receivable (December 31, 2020, four customers accounted for $17.6 million).

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

Three months ended March 31, ($ thousands)	**2021**	2020
Light oil	**$58,262**	$54,359
Heavy oil	**11,467**	813
Natural gas	**14,873**	7,755
Natural gas liquids	**8,094**	2,945
Oil and natural gas revenue	**$92,696**	$65,872
Processing income	**738**	411
Total revenue	**$93,434**	$66,283

Refer to note 4 for a listing of physical delivery contracts as at March 31, 2021.

Included in accounts receivable at March 31, 2021 was $35.2 million (December 31, 2020 - $24.2 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 March 31, 2021, 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, 2020	$2,076,327	$1,995	$2,078,322
Right-of-use assets	–	332	332
Property acquisitions	111,339	–	111,339
Cash additions	102,691	284	102,975
Decommissioning costs	45,850	–	45,850
Stock-based compensation	897	–	897
Transfer from exploration and evaluation assets (note 8)	148	–	148
Balance at December 31, 2020	2,337,252	2,611	2,339,863
Property acquisitions (note 7)	146,091	–	146,091
Cash additions	48,173	176	48,349
Decommissioning costs	(7,711)	–	(7,711)
Stock-based compensation	1,670	–	1,670
Transfer from exploration and evaluation assets (note 8)	218	–	218
Disposals	(285)	–	(285)
Balance at March 31, 2021	$2,525,408	$2,787	$2,528,195
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2020	$876,189	$1,183	$877,372
Depletion and depreciation	119,667	394	120,061
Impairment	399,000	–	399,000
Balance at December 31, 2020	1,394,856	1,577	1,396,433
Depletion and depreciation	30,291	92	30,383
Disposals	(199)	–	(199)
Balance at March 31, 2021	$1,424,948	$1,669	$1,426,617

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2020	$942,396	$1,034	$943,430
At March 31, 2021	$1,100,460	$1,118	$1,101,578

For the three months ended March 31, 2021 the Company disposed of a 4% gross overriding royalty on a select portion of the Nipisi properties acquired (see note 7) for proceeds of $13.5 million and recorded a gain on disposition of $7.5 million. The Company also disposed of a non-core property for proceeds of $0.4 million and recorded a gain on sale of $0.3 million.

The calculation of depletion at March 31, 2021 includes estimated future development costs of $660,797 (December 31, 2020 – $637,332) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $81,713 (December 31, 2020 – $79,357).

At March 31, 2021 there were no indicators of impairment or reversal of impairment identified on any of the Company's CGU's within property, plant and equipment and no impairment test was performed, as compared with the comparative period ended March 31, 2020 when the Company identified indicators of impairment and recorded an impairment charge of $381.0 million. Certain facilities, surface and office leases are included in property, plant and equipment as right-of-use assets:

($ thousands)	Processing facilities	Surface leases	Office leases	Total
As at January 1, 2020	$9,402	$1,736	$ –	$11,138
Lease additions	–	–	332	332
Depletion and depreciation	(1,366)	(150)	(145)	(1,661)
Impairment	(3,123)	(308)	–	(3,431)
As at January 1, 2021	$4,913	$1,278	$ 187	$6,378
Depletion and depreciation	(299)	(36)	(75)	(410)
Balance at March 31, 2021	$4,614	$1,242	$112	$5,968

7. Acquisitions:

On March 25, 2021, the Company completed two concurrent acquisitions of certain oil and gas properties located in the Provost and Nipisi areas of Alberta (the "Acquisitions") from two separate unrelated parties.

The first acquisition, included assets in both the Provost and Nipisi areas (the "Acquisition 1") was completed for total cash consideration of $102.6 million. There were $0.7 million of transaction costs expensed in earnings. The acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of March 25, 2021. Assets acquired in this transaction will be included in the Viking oil cash-generating unit ("CGU") and the Clearwater oil CGU. Assets held for sale relate to the GORR disposition on the Acquisition 1 Nipisi area assets.

The determination of the purchase price, based on management's preliminary estimate of fair values, is as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	103,859
Assets held for sale (note 6)		3,571
Decommissioning obligations		(4,820)
Net assets acquired	**$**	**102,610**
Purchase consideration:		
Cash	$	102,610
Total purchase consideration	**$**	**102,610**

The above amounts are estimates, which were made by management at the time of preparation of these condensed consolidated interim financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized through the final statement of adjustments.

The fair value of property, plant and equipment has been estimated with reference to an internally prepared reserves evaluation for the acquired properties. The estimated proved and probable oil and natural gas reserve and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk free rate of 8%.

Oil and natural gas revenue of $1.0 million and a net income of $0.3 million are included in the statement of loss for the Acquisition 1 assets since the closing date of March 25, 2021.

If the acquisition had occurred on January 1, 2021, the incremental oil and natural gas revenue and income recognized for the period ended March 31, 2021 and the pro forma results would have been as follows:

Period ended March 31, 2021 ($ thousands)	As stated	Acquisition 1 Prior to acquisition	*(unaudited)* Pro Forma
Oil and natural gas revenue	$92,696	$11,305	$104,001
Net income (loss)	(166)	2,314	2,148

(1) This pro-forma information is not necessarily indicative of results of operations that would have resulted had the acquisition been effective on the dates indicated or the results that may be obtained in the future.

The second acquisition in the Nipisi area (the "Acquisition 2") was completed for total cash consideration of $34.4 million including $0.9 million of capitalized transaction costs and the issuance of 4.9 million common shares of the Company. Based upon Tamarack's share price on the date of closing of $2.09 per share, the total consideration was approximately $44.6 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction will be included in the Clearwater oil CGU. Assets held for sale relate to the GORR disposition on the Acquisition 2 Nipisi area assets.

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

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	42,232
Assets held for sale (note 6)		2,409
Decommissioning obligations		(65)
Net assets acquired	**$**	**44,576**
Purchase consideration:		
Cash consideration	$	34,358
Share consideration (4,888,889 common shares)		10,218
Total purchase consideration	**$**	**44,576**

8. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2020	$25,854
Additions	568
Transfer to property, plant and equipment (note 6)	(148)
Balance at December 31, 2020	26,274
Additions	355
Transfer to property, plant and equipment (note 6)	(218)
Balance at March 31, 2021	$26,411
Accumulated amortization and impairment:	
Balance at January 1, 2020	$24,217
Amortization	597
Balance at December 31, 2020	24,814
Amortization	161
Balance at March 31, 2021	$24,975
	Total
Carrying amounts:	
At December 31, 2020	$1,460
At March 31, 2021	$1,436

9. 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 $248.4 million at March 31, 2021 (December 31, 2020 – $233.9 million), which is expected to be incurred between 2021 and 2045. A risk-free rate of 2.0% (December 31, 2020 – 1.2%) and an inflation rate of 1.7% (December 31, 2020 – 1.5%) is used to calculate the present value of the decommissioning obligations at March 31, 2021 as presented in the table below:

($ thousands)	**Three months ended March 31, 2021**	Year ended December 31, 2020
Balance, beginning of the period	**$245,437**	$184,846
Liabilities incurred	**4,311**	3,839
Liabilities acquired (note 7)	**4,885**	17,388
Change in estimates	**(18,733)**	20,051
Change in discount rate on acquisition	**6,711**	21,960
Expenditures	**(589)**	(3,825)
Site rehabilitation program grant	**(124)**	(1,395)
Liabilities disposed	**(26)**	–
Accretion	**820**	2,573
Balance, end of the period	**$242,692**	$245,437

Revisions due to the change of discount rate on acquisition of $6.7 million results from the difference between the fair value discount rate on the acquisition date and the subsequent revaluation using the risk-free rate.

The change in estimate for the three months ended March 31, 2021 resulted from decommissioning obligations being revalued using a risk-free rate of 2.0% and an inflation rate of 1.7% as opposed to a risk-free rate of 1.2% and an inflation rate of 1.5% used at December 31, 2020.

During the three months ended March 31, 2021, approximately $0.1 million (December 31, 2020 – $1.4 million) was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work.

Timing of decommissioning obligation expenditures expected to be incurred are:

($ thousands)	As at March 31, 2021
Decommissioning obligations – Less than 1 year	$7,411
Decommissioning obligations – Greater than 1 year	235,281
Total	$242,692

10. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities, surface leases and the Company's head office lease. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the three months ended March 31, 2021 were between 4.5% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at March 31, 2021:

($ thousands)	Three months ended March 31, 2021	Year ended December 31, 2020
Balance, beginning of the period	**$10,154**	$12,170
Lease additions	–	332
Interest expense	**184**	840
Lease payments	**(840)**	(3,188)
Balance, end of the period	**$9,498**	$10,154
Current portion	**$2,549**	$2,484
Long term portion	**$6,949**	$7,670

Undiscounted cash outflows relating to the lease liabilities are:

($ thousands)	Three months ended March 31, 2021	Year ended December 31, 2020
Less than 1 year	**$3,102**	$3,155
Years 2 and 3	**5,811**	6,140
Years 4 and 5	**3,019**	3,110
Thereafter	**2,069**	2,309
Total	**$14,001**	$14,714

11. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Three months ended March 31, ($ thousands)	2021	2020
Source/(use) of cash:		
Accounts receivable	**$(13,725)**	$10,032
Prepaid expenses and deposits	**(976)**	318
Accounts payable and accrued liabilities	**22,863**	15,153
	$8,162	$25,503
Related to operating activities	**$(2,211)**	$6,099
Related to financing activities	**$1,675**	$ –
Related to investing activities	**$8,698**	$19,404

The following are included in cash provided by operating activities:

Three months ended March 31, ($ thousands)	2021	2020
Interest paid in cash on bank debt	**$2,611**	$1,950
Bank renewal fees	**271**	–
Interest paid on lease liabilities	**184**	224

12. Shareholders' equity:

a) Share capital:

At March 31, 2021, the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value. At March 31, 2021, Tamarack had issued and outstanding 298,326,677 Common Shares (December 31, 2020 – 262,776,395). No preferred shares have been issued.

On March 25, 2021, the Company issued 30,303,000 shares at $2.25 per common share for total gross proceeds of $68.2 million. Share issue costs in the amount of $3.2 million were incurred in association with the bought deal financing .

On March 25, 2021, the Company issued 4,888,889 common shares in connection with Acquisition 2 (note 7).

On April 15, 2021, the over-allotment option granted on the March 25, 2021 share issuance was exercised and the Company issued 3,030,300 Common Shares at $2.25 per share for total gross proceeds of $6.8 million.

b) Treasury shares:

As at March 31, 2021, 388,349 Common Shares remain classified as treasury shares to be used for future settlements of restricted share units ("RSUs")and performance share units ("PSUs") (December 31, 2020 – 746,742 Common Shares).

13. Net loss per share:

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

($ thousands, except per share amounts)	2021	2020
Net loss	**$(166)**	$(251,321)
Weighted average shares - basic	**265,415**	222,048
Weighted average shares - diluted	**265,415**	222,048
Net loss per share-basic	**$(0.00)**	$(1.13)
Net loss per share-diluted	**$(0.00)**	$(1.13)

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the year ended March 31, 2021, 15.6 million Common Shares issuable upon the exercise and/or settlement of stock options ("Options"), RSUs, PSUs and TAC Preferred Shares (as defined below) were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss (March 31, 2020 – 14.9 million).

14. Bank debt:

The Company currently has available a revolving credit facility in the amount of $295 million and a $30 million operating facility (collectively, the "Facility") with a syndicate of lenders. Concurrent with the close of the Acquisitions on March 25, 2021, the Facility increased from a total of $275 million to a total of $325 million. The Facility will be subject to its next extension by November 30, 2021. If not extended on November 30, 2021, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on both a net debt-to-cash-flow ratio and the total amount drawn down as defined in the Facility. The interest rate will vary depending on the lending vehicle employed, the total loan value drawn and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and London Inter-bank Offered Rate Based Loans ("LIBOR") will vary based on a BA pricing grid from a low of the banks' posted rates plus 3.00% to a high of the banks' posted rates plus 5.00%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 2.00% to a high of the banks' prime rates plus 4.00%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.25% 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 March 31, 2020, the Facility was secured by a $1.0 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's estimated proved and probable oil and natural gas reserves and forecasted commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by November 30, 2021.

At March 31, 2021, the Company had utilized the Facility in the amount of $270.8 million (December 31, 2020 – $210.9 million). The interest rate applicable to the drawn amounts as of this date was 4.48%. As at March 31, 2021, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility (December 31, 2020 – $0.2 million). There are no financial covenants governing the Facility.

The Company manages its credit facility using a combination of prime rate loans, bankers' acceptance notes and US dollar denominated LIBOR loans. During the quarter ended March 31, 2021, concurrent with the drawdown of US dollar LIBOR loans, the Company entered into cross-currency swaps ("CCS") to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of interest and principal repayments. At March 31, 2020, the Company had drawn US$60.0 million, fixed at notional amounts of $75.8 million through various CCS maturing at various times across the month of April 2021 (December 31, 2020 – the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS).

Subsequent to March 31, 2021, the Company entered into a definitive agreement to acquire Anegada Oil Corp., with an expected acquisition closing date on or before May 31, 2021. Tamarack's credit syndicate has provided commitments to increase the available capacity under the Company's credit facilities to $600 million and extend the revolving period to May 31, 2022, concurrent with the close of the Anegada Acquisition.

15. Share-based payments:

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

Three months ended March 31, ($ thousands)	**2021**	2020
Non-cash stock- based compensation		
Stock options	**$100**	$22
RSU's	**727**	912
PSU's	**2,493**	345
Total non-cash stock-based compensation:	**$3,320**	$1,279
Total capitalized costs	**(1,670)**	(329)
Total expensed non-cash stock-based compensation	**$1,650**	$950

(a) **Preferred share plan:**

At March 31, 2021, there are 740,307 (December 31, 2020 – 740,307) preferred shares of Tamarack Acquisition Corp. (the "TAC Preferred Shares") issued and outstanding. At March 31, 2021, the TAC Preferred Shares were fully vested and exchangeable into 711,834 (December 31, 2020 – 711,834) 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.

(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 20.9 million Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at March 31, 2021, there was an aggregate of 14.9 million Options, RSUs and PSUs issued and outstanding.

Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.6 million Options granted during the three months ended March 31, 2021 (December 31, 2020 – 0.6 million).

The fair value of each Option granted during the three months ended March 31, 2021 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:

	2021
Risk free rate (%)	**0.87**
Expected volatility (%)	**61**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**1.16**

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

	Number of Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2020	2,193	$3.01
Granted	559	1.13
Forfeited/expired	(848)	2.88
Outstanding, December 31, 2020	1,904	$2.51
Granted	593	2.25
Outstanding, March 31, 2021	**2,497**	**$2.45**

The range of exercise prices of the Options outstanding and exercisable at March 31, 2021 is as follows:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 0.64 – 2.50	1,152	$1.71	4.5	186	$1.13
$ 2.51 – 2.81	524	$2.60	2.5	416	$2.61
$ 2.82 – 3.44	821	$3.40	0.7	822	$3.40
$ 0.64 – 3.44	**2,497**	**$2.45**	**2.8**	**1,424**	**$2.87**

(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 1.6 million RSUs granted during the three months ended March 31, 2021 (December 31, 2020 – 2.0 million).

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

The following table summarizes information about the RSUs:

	Number of RSUs (thousands)
Outstanding, January 1, 2020	6,987
Granted	1,986
Exercised	(3,363)
Forfeited	(245)
Outstanding, December 31, 2020	5,365
Granted	1,639
Exercised	(300)
Outstanding, March 31, 2021	**6,704**
Exercisable, March 31, 2021	**2,735**

(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 2.3 million PSUs granted during the three months ended March 31, 2021 (December 31, 2020 – 1.7 million).

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

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2020	2,157
Awarded	1,657
Forfeited	(250)
Outstanding, December 31, 2020	3,564
Awarded	2,259
Exercised	(58)
Forfeited	(36)
Outstanding, March 31, 2021	**5,729**
Earned, March 31, 2021	**2,401**
Exercisable, March 31, 2021	**–**

16. Commitments:

The following table summarizes the Company's commitments as at March 31, 2021:

($ thousands)	2021	2022	2023	2024	2025+
Lease[(1)]	163	229	229	229	172
Take or pay commitments[(2)]	2,976	4,023	3,894	–	–
Gas transportation[(3)]	2,203	1,955	640	143	7
Capital commitments[(4)]	25,000	65,000	50,000	–	–
Total	30,342	71,207	54,763	372	179

(1) Relates to the variable operating costs, which are a non-lease component of the Company's head office sublease and sublease expansion. The head office sublease and sublease expansion commence at dates of April 1, 2021 and June 1, 2021, respectively and expire on September 30, 2025. At sublease and sublease expansion commencement the Company will recognize estimated lease liabilities and related right-of-use assets of $1.7 million and $0.5 million, respectively.

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

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

(4) Commitment of $140.0 million of capital to further develop the GORR Nipisi/Clearwater lands prior to December 31, 2023.

17. Contingency:

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

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

18. Subsequent events:

Subsequent to the end of the quarter, Tamarack entered into a definitive agreement to acquire Anegada Oil Corp. – a privately held, pure play, Charlie Lake light oil producer – for total net consideration of $494 million, after deducting the proceeds from a newly created 2% GORR on the acquired assets.The total net consideration consists of $247.5 million in cash and debt (net of GORR), subject to adjustment, and approximately 105.3 million Common Shares at a deemed price of $2.34 per share. Tamarack's credit syndicate has provided commitments to increase the available capacity under the Company's credit facilities to $600 million and extend the revolving period to May 31, 2022, concurrent with the close of the Anegada Acquisition. The Anegada Acquisition is subject to certain customary closing conditions and is expected to close on or before May 31, 2021.

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)(4)

Jeff Boyce(1)(4)

John Leach(1)(2)

Ian Currie(2)(4)

Rob Spitzer(2)(3)

Marnie Smith(1)(3)

John Rooney(1)(3)

Brian Schmidt

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

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Martin Malek
VP Corporate Planning & Business Development

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Contact Information

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