MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months and years ended December 31, 2021 and 2020. This MD&A is dated and based on information available as at March 3, 2022 and should be read in conjunction with the audited consolidated financial statements ("financial statements") and the notes thereto for the years ended December 31, 2021 and 2020. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2021, 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 Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company uses certain Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" beginning on page 24. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

2021 – A Year of Strategic Transformation

2021 was a transformational year for the Company as we advanced our strategy of driving long term sustainable and resilient free funds flow (see "Capital Management Measures") growth through the repositioning and further consolidation of the Company into the Charlie Lake and Clearwater oil plays, complementing our highly economic waterflood assets.

Tamarack closed three separate transactions to acquire assets in the Clearwater oil play in 2021. These acquisitions enhanced our operated position in the play, which began with a series of transactions in the fourth quarter of 2020. In addition, Tamarack announced the acquisition of Crestwynd Exploration during the fourth quarter of 2021, which closed in the first quarter of 2022, further consolidating the Company's position in the Southern Clearwater fairway. In total Tamarack's Clearwater land position, pro-forma the Crestwynd acquisition will be greater than 445 net sections in Nipisi, West Marten Hills and Southern Clearwater.

Tamarack also successfully gained entrance into the Charlie Lake light oil play through the acquisition of Anegada Oil Corp. which closed on June 1st, establishing a significant footprint and strategic infrastructure ownership. The Company continued to augment and consolidate its position in the play throughout 2021 and holds approximately 325 net sections further enhancing our portfolio of resilient free funds flow generating assets.

Together these transformative acquisitions, combined with the successful execution of the Company's capital expenditure program have resulted in corporate production growth of 83% on a year over year basis. This growth, combined with the sustainable and resilient free funds flow platform has allowed the Company to transition to a return of capital model through both a base dividend and enhanced return framework in 2022.

Q4 2021 Operational and Financial Highlights

- Achieved quarterly production volumes of 40,384 boe/d in Q4/21, representing an 83% increase compared to the same period in 2020.
- Generated adjusted funds flow of $124.1 million in Q4/21 ($0.31 per share basic and $0.30 per share diluted) compared to $28.9 million in the same period in 2020 ($0.13 per share basic and diluted).
- Generated free funds flow (see "Capital Management Measures"), excluding acquisition expenditures, of $82.4 million and net income of $140.4 million during the quarter.
- Invested $41.7 million in exploration and development ("E&D") capital expenditures, excluding acquisition expenditures, during Q4/21.This contributed to the drilling of six (6.0 net) Viking oil wells, eleven (8.5 net) Clearwater oil wells, four (4.0 net) Charlie Lake oil wells and two (2.0 net) water source wells.
- Exited the year with $463.3 million of net debt (see "Capital Management Measures") and net debt to Q4/21 annualized adjusted funds flow (see "Capital Management Measures") of 0.9x.
- Successfully executed on further tuck-in acquisitions in the Charlie Lake light oil and Eyehill waterflood plays for approximately $17.1 million during the quarter. These acquisitions further our strategy of both adding to and enhancing the resiliency of our drilling inventory and free funds flow profile.

2021 Operational and Financial Highlights

- Achieved yearly production volumes of 34,562 boe/d in 2021, representing a 57% increase compared to the same period in 2020.
- Generated adjusted funds flow of $340.3 million for the year ended December 31, 2021 ($0.96 per share basic and $0.94 per share diluted) compared to $122.7 million in the same period in 2020 ($0.55 per share basic and diluted).
- Generated free funds flow, excluding acquisition expenditures, of $149.1 million and net income of $390.5 million for the year.
- Invested $191.2 million in exploration and development ("E&D") capital expenditures, excluding acquisition expenditures, during the full year 2021. This contributed to the drilling of forty (40.0 net) Viking oil wells, forty-three (40.0 net) Clearwater oil wells, thirteen (13.0 net) Charlie Lake oil wells, two (0.8 net) Falher gas wells and eight (8.0 net) water source wells.

2021 Acquisitions Summary

For the year ended December 31, 2021 Tamarack completed a number of acquisitions primarily to consolidate and enhance the Company's operated position in the Clearwater oil play and to gain entrance into the Charlie Lake oil play.

The following table summarizes the Company's acquisitions for the year ended December 31, 2021:

CGU	Area	Acquisition date	Consideration Cash	Shares
Viking oil, Clearwater oil	Northern Clearwater, Eyehill	March 25, 2021	$102,610	$ –
Clearwater oil	Northern Clearwater	March 25, 2021	34,358	10,218
Charlie Lake oil	Charlie Lake	June 1, 2021	258,201	280,209
Clearwater oil	Southern Clearwater	August 31, 2021	35,727	–
Various	Other minor	Various	25,360	–
December 31, 2021			**$456,256**	**$290,427**

Further discussion related to the Company's acquisitions and dispositions is included in the Acquisitions and Dispositions section of this MD&A on page 17.

Climate change, Sustainability and COVID-19 Impacts on 2021

Tamarack continues to consider the impacts of climate change and the COVID-19 pandemic and the financial and operational challenges these two global events have had in 2021 and will continue to impact the Company during the years ahead.

Climate Change

The Company has considered and continues to consider the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources.

Emissions, carbon and other regulations impacting climate and climate related matters, are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board ("ISSB") was created on November 3, 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. As at December 31, 2021, the ISSB has not issued any new sustainability disclosure standards or exposure drafts. In addition, the Canadian Securities Administrators have issued a proposed National Instrument ("NI 51-107") Disclosure of Climate-related Matters. The cost to comply with these standards, and others, that may be developed or evolved over time, is not quantifiable at this time. Significant estimates and judgments have been made by management in the preparation of the financial statements in areas of property, plant and equipment, depletion, impairment and impairment reversal, reserves estimates, decommissioning obligations, credit facilities and share capital.

Sustainability

Tamarack continues to be committed to advancing our ESG practices as outlined in our second annual Sustainability Report released on December 2, 2021. 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.

Based on the Company's commitment and approach to Sustainability, the Company has amended its existing revolving bank facility to a Sustainability Linked Lending Facility ("SLL Facility') that incorporates sustainability-linked interest rate terms, see Bank Debt on page 22. Subsequent to year end, the Company issued $200.0 million of senior unsecured sustainability-linked notes (the "Notes") due May 10, 2027 that also incorporate sustainability-linked interest rate terms (see Note 24 Subsequent Events in the Company's financial statements).

COVID-19

Tamarack continues to proactively respond to the safety and financial challenges of the COVID-19 pandemic. Management notes that forecasting the timing of a full and sustainable economic recovery is challenging with the outlook on crude oil demand significantly dependent on the status of COVID-19 virus variants, vaccine effectiveness, global vaccine rollouts, changes in social and travel restrictions, and the impact of all of these factors on global economic activity. The recovery in oil demand as a result of the easing of COVID-19 restrictions, combined with a prudent supply policy implemented by the OPEC+ alliance, has resulted in crude oil prices recovering to pre-pandemic levels. However, the crude oil market remains subject to high levels of uncertainty given the emergence of the Omicron variant of the COVID-19 virus, which could result in renewed social and travel restrictions. Changes in global crude oil demand, supply, and inventories could all be impacted by the COVID-19 pandemic in the near term and crude oil markets may continue to be subject to significant volatility in 2022. Management continues to monitor commodity prices, currency exchange rates and overall industry activity levels and incorporates these factors into the Company's capital expenditure plans. 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.

Production

Year-over-Year	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	**2021**	2020	% change
Production						
Light oil (bbls/d)	**18,487**	10,353	79	**15,670**	11,155	40
Heavy oil (bbls/d)	**5,616**	319	1,661	**4,613**	204	2,161
Natural gas liquids (bbls/d)	**3,899**	2,421	61	**3,408**	1,930	77
Natural gas (mcf/d)	**74,291**	53,738	38	**65,226**	52,426	24
Total (boe/d)	**40,384**	22,049	83	**34,562**	22,027	57
Percentage of oil and NGL	**69%**	59%	17	**69%**	60%	15

Average production for Q4/21 and the year ended December 31, 2021 increased 83% and 57%, respectively, compared to the same periods in 2020 due to the acquisitions that closed throughout 2021 and the 2021 development programs, partially offset by expected declines of existing base production. The Company's oil and NGL weighting for Q4/21 and the year ended December 31, 2021 is 17% and 15% higher, respectively, as compared to the same periods in 2020.

Petroleum and Natural Gas Sales

Year-over-Year	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	**2021**	2020	% change
Revenue ($ thousands)						
Light oil	**$150,724**	$45,367	232	**$449,888**	$169,261	166
Heavy oil	**37,039**	1,264	2,830	**108,690**	2,857	3,704
Natural gas liquids	**19,760**	5,434	264	**51,958**	14,767	252
Natural gas	**34,765**	12,173	186	**88,036**	34,011	159
Total	**$242,288**	$64,238	277	**$698,572**	$220,896	216
Average realized price:						
Light oil ($/bbl)	**88.59**	47.63	86	**78.64**	41.46	90
Heavy oil ($/bbl)	**71.69**	43.12	66	**64.56**	38.36	68
Natural gas liquids ($/bbl)	**55.09**	24.40	126	**41.77**	20.90	100
Combined average oil and NGL ($/boe)	**80.55**	43.22	86	**70.60**	38.42	84
Natural gas ($/mcf)	**5.09**	2.46	107	**3.70**	1.77	109
Revenue ($/boe)	**65.21**	31.67	106	**55.38**	27.40	102
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**77.17**	42.67	81	**67.93**	39.40	72
Edm Par Differential (US$/bbl)	**3.11**	4.07	(24)	**3.88**	5.33	(27)
WCS differential (US$/bbl)	**14.65**	9.30	58	**13.04**	12.57	4
Edmonton Par (Cdn$/bbl)	**93.26**	50.25	86	**80.25**	45.32	77
Hardisty Heavy (Cdn$/bbl)	**78.68**	43.42	81	**68.75**	35.61	93
NYMEX monthly settlement (US$/mmbtu)	**5.83**	2.66	119	**3.79**	2.08	82
AECO daily index (Cdn$/mcf)	**4.04**	2.55	58	**3.46**	2.20	57
AECO monthly index (Cdn$/mcf)	**4.22**	2.45	72	**3.12**	2.13	46

Revenue per boe from oil, natural gas and NGL sales for Q4/21 and the year ended December 31, 2021 increased by 106% and 102%, respectively, compared to the same periods in 2020. These increases were due to improved and stabilized commodity prices realized in 2021 compared to the depressed prices realized in 2020 as a result of the COVID-19 pandemic, for the comparative periods.

The WTI benchmark price for Q4/21 and the year ended December 31, 2021 averaged US$77.17/bbl, and US$67.93/bbl, increases of 81% and 72%, respectively, over the WTI benchmark for the same periods in 2020 of US$42.67/bbl, and US$39.40/bbl.

In Q4/21 and for the year ended December 31, 2021, WTI pricing improved on average due to increased global demand resulting from the easing of COVID-19 social and travel restrictions, combined with a prudent supply policy implemented by the OPEC+ alliance.

The Edmonton Par light oil differential for Q4/21 narrowed to an average of US$3.11/bbl and the WCS heavy oil differential widened to an average of US$14.65/bbl. The US$11.54/bbl spread between Edmonton Par light oil and WCS in Q4/21 is reflective of more normalized pricing versus the US$5.23/bbl spread in the same quarter in 2020. Fluctuating diluent costs continue to shape the heavy oil market in Alberta. Repricing from both Enbridge apportionment and Trans Mountain's Force Majeure took place in Q4/21 causing a wider spread between benchmark pricing and realized wellhead differentials. Combined, these factors contributed to a realized light oil wellhead price for Q4/21 of $88.59/bbl versus $47.63/bbl in the same period in 2020 and a realized heavy oil wellhead price of $71.69/bbl in Q4/21 compared to $43.12/bbl in Q4/20.

The Edmonton Par light oil differential for the year ended December 31, 2021 averaged US$3.88/bbl and the WCS heavy oil differential averaged US$13.04/bbl. Light oil wellhead price for the year ended December 31, 2021 was $78.64/bbl versus $41.46/bbl in the same period of 2020 and a realized heavy oil wellhead price of $64.56/bbl compared to $38.36/bbl over the same period in 2020.

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 126% to $55.09/bbl in Q4/21 from $24.40/bbl in Q4/20. Similarly, realized NGL prices for the year ended December 31, 2021 increased 100% to $41.77/bbl from $20.90/bbl in the same period of 2020. These increases are due largely to the improved WTI price over the comparative periods, which is the basis for condensate and butane pricing.

Tamarack's realized natural gas price increased 107% to $5.09/mcf in Q4/21 from $2.46/mcf in Q4/20. The AECO daily benchmark price increased 58% to $4.04/mcf in Q4/21 from $2.55/mcf in Q4/20 while the NYMEX monthly settlement price increased 119% to US$5.83/mmbtu in Q4/21 from US$2.66/mmbtu in Q4/20.

The Company's realized natural gas price increased 109% to $3.70/mcf in the year ended December 31, 2021 from $1.77/mcf in the same period of 2020. The AECO daily benchmark price increased 57% to $3.46/mcf in the year ended December 31, 2021 from $2.20/mcf for the same period in 2020 while the NYMEX monthly settlement price increased 82% to US$3.79/mmbtu from US$2.08/mmbtu in the respective year then ended.

The increases in benchmark prices for Q4/21 and the year-ended December 31, 2021, compared to the same periods in 2020, were primarily due to increasing worldwide demand, decreasing inventories and lower supply as a result of decreased drilling activity in 2020.

The increases in Tamarack's realized price deviates from the index increases due to the Company's diversification strategy that balances pricing exposure over multiple markets. In addition, Tamarack continues to manage commodity price risk through financial and physical hedges.

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. At December 31, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables:

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**1,250**	**4,250**	**9,250**	**3,500**
	Average Bought Put (US$/bbl)	$52.60	$54.76	$58.57	$58.50
	Average Sold Call (US$/bbl)	$87.17	$90.46	$93.51	$92.13
	Average Premium (US$/bbl)	$2.00	$2.01	$2.00	$2.00
WTI three-way reverse collar	***Volume (bbls/d)***	**1,250**	**2,500**	**1,250**	**750**
	Average Bought Put (US$/bbl)	$55.00	$54.40	$55.00	$55.00
	Average Sold Call (US$/bbl)	$70.00	$70.00	$70.00	$70.00
	Average Bought Call (US$/bbl)	$73.29	$72.99	$73.37	$73.98
	Average Premium (US$/bbl)	$2.00	$2.00	$2.00	$2.00
WTI Put	***Volume (bbls/d)***	**19,750**	**7,750**	**750**	**750**
	Average Bought Put (US$/bbl)	$68.76	$52.71	$53.10	$53.10
	Average Premium (US$/bbl)	$3.97	$2.70	$3.10	$3.10
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**7,000**	**8,500**	**500**	**500**
	Average Price (US$/bbl)	($3.86)	($3.82)	($4.00)	($4.00)
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**3,000**	**4,000**	**500**	**500**
	Average Price (US$/bbl)	($12.58)	($11.79)	($12.00)	($12.00)

		Winter 21-22	Summer 22
Natural Gas Derivatives			
AECO 5A	***Volume (GJ/d)***	**25,000**	**30,000**
	Average Price (CAD/GJ)	$3.14	$2.44

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	***Amount ($US/month)***	**$7,000,000**	**$6,500,000**	–	–
	Average Forward Rate (CAD/USD)	1.2415	1.2440	–	–
CAD/USD target average rate forward(1)	***Amount ($US/month)***	**$1,500,000**	**$1,500,000**	**$500,000**	**$500,000**
	Average Forward Rate (CAD/USD)	1.2433	1.2433	1.2640	1.2640
CAD/USD forward accumulator(2)	***Amount ($US/month)***	**$833,333**	**$833,333**	–	–
	Average Forward Rate (CAD/USD)	1.2500	1.2500	–	–

(1) Comprised of three $500,000 tranches in Q1 and Q2 2022 and one $500,000 in Q3 and Q4 2021, with a maximum benefit to Tamarack over the term for each tranche of 0.03 value points; once maximum value is reached, the instrument immediately terminates.

(2) Accumulates for the monthly period at a rate of 1.25 based on the rate during the setting period six months prior.

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

At December 31, 2021, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of $13.1 million (December 31, 2020 - $10.2 million net liability) recorded on the balance sheet. The Company recorded an unrealized gain of $39.7 million and $6.7 million in earnings for the three months and year ended December 31, 2021, respectively, compared to an unrealized loss of $10.0 million and $6.1 million during the same periods 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 December 31, 2021, the Company has entered into the following financial contracts (excluding contracts acquired in the acquisition of Crestwynd):

		Q2 2022	Q3 2022	Q4 2022	Q1 2023
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**–**	**2,500**	**8,500**	**3,500**
	Average Bought Put (US$/bbl)	–	$60.00	$57.06	$55.71
	Average Sold Call (US$/bbl)	–	$101.24	$111.96	$116.74
	Average Premium (US$/bbl)	–	$1.75	$1.93	$2.00
WTI Put	***Volume (bbls/d)***	**1,250**	**4,000**	**3,500**	**1,000**
	Average Bought Put (US$/bbl)	**$57.98**	$56.25	$57.14	$60.00
	Average Premium (US$/bbl)	**$0.75**	$2.98	$3.20	$3.27
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**2,000**	**7,500**	**7,500**	**–**
	Average Price (US$/bbl)	($3.00)	($3.57)	($3.57)	–
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**1,000**	**7,000**	**5,000**	**–**
	Average Price (US$/bbl)	($11.95)	($12.00)	($12.10)	–

		Winter 22-23
Natural Gas Derivatives		
AECO 5A	***Volume (GJ/d)***	**10,000**
	Average Price (CAD/GJ)	$3.85
AECO 7A two-way collar	***Volume (GJ/d)***	**15,000**
	Average Bought Put (CAD/GJ)	$3.37
	Average Sold Call (CAD/GJ)	$5.17

Subsequent to December 31, 2021, the Company entered into agreements to reprice certain agreements, raising the value of the bought puts and increasing the associated premiums. The values at December 31, 2021 and the new values after repricing are summarized in the table below.:

		As at Dec 31, 2021 **Q2 2022**	Subsequent to Year End **Q2 2022**
West Texas Intermediate Crude Oil Derivatives			
WTI two-way collar	***Volume (bbls/d)***	**500**	**500**
	Average Bought Put (US$/bbl)	$60.00	$65.00
	Average Sold Call (US$/bbl)	$95.50	$95.50
	Average Premium (US$/bbl)	$2.00	$2.98
WTI Put	***Volume (bbls/d)***	**6,500**	**6,500**
	Average Bought Put (US$/bbl)	$52.49	$65.00
	Average Premium (US$/bbl)	$3.03	$4.20

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue.

At December 31, 2021, the Company held the following physical commodity contracts:

		Winter 21-22
Natural Gas Physical		
AECO 5A	***Volume (GJ/d)***	**15,000**
	Average Price (CAD/GJ)	$3.00

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

Royalties

Year-over-Year	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	**2021**	2020	% change
Royalty expenses ($ thousands)	**$35,283**	$6,713	426	**$102,132**	$24,540	316
$/boe	**9.50**	3.31	187	**8.10**	3.04	166
Percent of sales (%)	**15**	10	50	**15**	11	36

Royalties as a percentage of revenue for both the three months and the year ended December 31, 2021 were higher than the same periods in 2020, due to the sliding scale nature of some oil royalties which increases the percentage during periods of high oil prices and the addition of the GORR in conjunction with the acquisitions that closed in 2021. The Company expects royalty rates as a percentage of revenue to increase to the 18% to 20% range for 2022 based on current forecast commodity pricing levels and increased production from lands subjected to GORRs.

On an absolute basis, royalty expense was higher in Q4/21 and the year ended December 31, 2021, compared to same periods in 2020 due to an increase in commodity prices, production and GORRs.

Net Production Expenses

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Production expenses	**$34,920**	$22,598	55	**$117,957**	$78,893	50
Less: processing income	**896**	635	41	**2,479**	1,177	111
Total net production expenses [(1)]	**$34,024**	$21,963	55	**$115,478**	$77,716	49
Total ($/boe) [(2)]	**$9.16**	$10.83	(15)	**$9.15**	$9.64	(5)

(1) Non-IFRS Financial Measure; See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" Section of this MD&A.

(2) Non-IFRS Financial Ratio; See "*Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures*" Section of this MD&A.

For the three months and year ended December 31, 2021, per unit net production expenses (see "Non-IFRS Financial Ratios") were lower compared to the same periods in 2020. This resulted from the acquisitions that closed during 2021 having lower per unit net production expenses compared to the corporate average before the acquisitions

For the three months and year ended December 31, 2021 on an absolute basis gross and net production expenses were higher compared to the same periods in 2020 due to higher production, partially offset by lower per unit net production expenses.

Transportation Expense

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Transportation expense - gas	**$2,776**	$1,132	145	**$8,574**	$4,546	89
Transportation expense - oil	**3,451**	664	420	**11,883**	3,076	286
Total transportation expense	**$6,227**	$1,796	247	**$20,457**	$7,622	168
Total ($/boe)	**$1.68**	$0.88	91	**$1.62**	$0.95	71

For the three months and year ended December 31, 2021, per unit transportation expenses were higher compared to the same periods in 2020. This increase was primarily the result of the acquisitions that closed in 2021 requiring oil to be trucked to sales points driven by the strongest operating netback (see "Non-IFRS Financial Measures"), which may result in higher transportation expenses.

For the three months and year ended December 31, 2021, total net transportation expenses were higher compared to the same periods in 2020 due to higher production, a larger proportion of volumes that require clean oil trucking and higher incremental firm transportation in the Company's Charlie Lake and Viking operating areas.

Operating Netback

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($/boe)	**2021**	2020	% change	**2021**	2020	% change
Average realized sales	**$65.21**	$31.67	106	**$55.38**	$27.40	102
Royalty expenses	**(9.50)**	(3.31)	187	**(8.10)**	(3.04)	166
Net production expenses (1)	**(9.16)**	(10.83)	(15)	**(9.15)**	(9.64)	(5)
Transportation expense	**(1.68)**	(0.88)	91	**(1.62)**	(0.95)	71
Operating field netback (1)	**44.87**	16.65	169	**36.51**	13.77	165
Realized hedging gain (loss)	**(8.25)**	0.52	(1,687)	**(6.40)**	4.09	(256)
Operating netback (1)	**$36.62**	$17.17	113	**$30.11**	$17.86	69

(1) Non-IFRS Financial Ratio; See "*Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures*" Section of this MD&A.

For the three months and year ended December 31, 2021, operating netbacks per boe (see "Non-IFRS Ratios") were higher than the same periods in 2020 primarily due to the higher commodity prices realized in 2021, partially offset by higher transportation expense, higher royalties and the realized hedging losses in 2021.

General and Administrative ("G&A") Expenses

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Gross costs	**$6,922**	$4,183	65	**$23,910**	$15,032	59
Capitalized costs and recoveries	**(1,903)**	(1,067)	78	**(5,871)**	(3,950)	49
General and administrative costs	**$5,019**	$3,116	61	**$18,039**	$11,082	63
Total ($/boe)	**$1.35**	$1.54	(12)	**$1.43**	$1.37	4

Net G&A costs on a per boe basis for the three months ended December 31, 2021 were lower compared to the same period in 2020, due to higher overall production levels, partially offset by increased staffing levels related to the acquisitions that closed in 2021.

Net G&A costs on a per boe basis for the year ended December 31, 2021 were higher compared to the same period in 2020, due to increased staffing levels related to the acquisitions that closed in 2021 and the Company receiving the Canada Emergency Wage Subsidy ("CEWS") during the year ended December 31, 2020 as compared to the year ended December 31, 2021 when the Company did not receive the CEWS. The higher costs were partially offset by higher overall production levels.

For the three months and year ended December 31, 2021 gross and net G&A costs (all excluding transaction costs) were higher compared to the same periods in 2020, due to increased staffing levels related to the acquisitions that closed in 2021.The Company incurred acquisition-related transaction costs in the amount of $8.1 million compared to no transaction costs in the same periods in 2020.

Stock-Based Compensation Expense

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Gross costs	**$2,810**	$1,596	76	**$9,558**	$6,397	49
Capitalized costs	**(631)**	(182)	247	**(3,588)**	(897)	300
Expensed stock-based compensation	**$2,179**	$1,414	54	**$5,970**	$5,500	9
Total ($/boe)	**$0.59**	$0.70	(16)	**$0.47**	$0.68	(31)

Stock-based compensation expense related to Stock Options, RSUs and PSUs for the three months and year ended December 31, 2021 was higher compared to the same periods 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 year ended December 31, 2021, the Company issued 0.9 million Stock Options (at a weighted average exercise price of $2.33 per share), 2.2 million RSUs and 2.9 million PSUs compared to 0.6 million Stock Options (at a weighted average exercise price of $1.13 per share), 2.0 million RSUs and 1.7 million PSUs during the same period in 2020.

Finance Expense

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Interest on bank debt	**$5,521**	$2,478	123	**$18,334**	$8,611	113
Fees associated with credit facility renewal	**1,274**	141	804	**2,359**	673	251
Interest on lease liabilities	**195**	196	(1)	**791**	840	(6)
Unrealized loss (gain) on foreign exchange	**(160)**	(2,962)	(95)	**1,266**	1,249	1
Unrealized loss (gain) on cross-currency swap	**105**	2,955	(96)	**(1,305)**	(1,311)	(0)
Accretion of decommissioning obligations	**1,421**	694	105	**4,895**	2,573	90
Total finance expense	**$8,356**	$3,502	139	**$26,340**	$12,635	108
Total ($/boe)	**$2.25**	$1.73	30	**$2.09**	$1.57	33
Average drawings on bank debt	**$481,570**	$200,499	140	**$393,404**	$203,925	93

Total finance expense for the three months and year ended December 31, 2021 was higher than the same periods in 2020 due to higher average drawings on bank debt resulting in increased interest on bank debt and fees associated with the redetermination of the credit facility with respect to the acquisitions that closed throughout 2021.

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

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Depletion and depreciation	**$61,852**	$26,833	131	**$211,622**	$120,061	76
Amortization of undeveloped leases	**197**	157	25	**715**	597	20
Total	**$62,049**	$26,990	130	**$212,337**	$120,658	76
Depletion and depreciation ($/boe)	**$16.65**	$13.23	26	**$16.78**	$14.89	13
Amortization ($/boe)	**0.05**	0.08	(38)	**0.06**	0.07	(14)
Total ($/boe)	**$16.70**	$13.31	25	**$16.84**	$14.96	13

For the three months and year ended December 31, 2021, DD&A expense per boe was higher relative to the same periods in 2020. The increase was due to acquisitions that closed in 2021 that have a higher DD&A expense per boe than the corporate average and the impairment reversal that was taken in Q2/21. For the three months and year ended December 2020, DD& A expense per boe was reduced by impairment charges 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 higher for the three months and year ended December 31, 2021 due to higher production and higher DD&A expense per boe.

Impairment (Impairment Reversal) of Property, Plant and Equipment

The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy not sourced from fossil fuels in its assessment of impairment and impairment reversal on its oil and gas properties, both as indicators of impairment and impairment reversal, and in the estimates and judgments involved in testing for impairment and impairment reversal. The estimated recoverable amount of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 20 years.

2021 Assessment

At December 31, 2021 there were indicators of reversal of impairment identified in the Company's Cardium oil cash-generating unit ("CGU"), Viking oil CGU and Penny oil CGU as a result of improved forward commodity prices for natural gas, condensate and oil associated with the proved and probable oil and natural gas reserves at December 31, 2021, and a resultant increase in proved and probable reserves as estimated in the Company's December 31, 2021 external independent qualified reserves evaluators report. The impairment reversal of $90.0 million was recorded as follows: the Cardium oil CGU reversed $14.3 million of historical impairment charges, the Viking oil CGU reversed $52.3 million of historical impairment charges and the Penny oil CGU reversed $23.4 million of historical impairment charges. The estimated recoverable amount of these CGUs as at December 31, 2021, net of decommissioning obligations, was $248.6 million for the Cardium oil CGU, $692.5 million for the Viking oil CGU and $83.4 million for the Penny oil CGU. The Viking oil CGU and Penny oil CGU have fully reversed all previous historical impairment charges, net of notional depletion. The estimated recoverable amount of the CGUs was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2021 at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the fair value less costs of disposal ("FVLCD") methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account higher forecasted oil and natural gas prices. The impairment reversal of $90.0 million was allocated to property, plant and equipment in the amount of $89.5 million and $0.5 million was allocated to the right-of-use assets.

At June 30, 2021, there were indicators of reversal of impairment identified in the Company's Cardium oil CGU and Viking oil CGU as a result of improved forward commodity prices for natural gas, condensate and oil associated with the proved and probable oil and natural gas reserves at June 30, 2021. The impairment reversal of $300.0 million was recorded as follows: the Cardium oil CGU reversed $140.0 million of historical impairment charges and the Viking oil CGU reversed $160.0 million of historical impairment charges. The estimated recoverable amount of these CGUs as at June 30, 2021, net of decommissioning obligations, was $257.2 million for the Cardium oil CGU and $643.8 million for the Viking oil CGU based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2020 and updated by the Company's internal reserves evaluator to June 30, 2021 for production; production costs; royalty costs; future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 25% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the FVLCD methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account higher commodity prices. The impairment reversal of $300.0 million was allocated to property, plant and equipment in the amount of $298.3 million and $1.7 million was allocated to the right-of-use assets.

The Company has recorded an aggregate impairment reversal of $390.0 million for the year ended December 31, 2021 of which $154.3 million related to the Cardium oil CGU, $212.3 million related to the Viking oil CGU and $23.4 million related to the Penny oil CGU. The aggregate impairment reversal was allocated to property, plant and equipment in the amount of $387.8 million and $2.2 million was allocated to right-of-use assets.

2020 Assessment

An impairment charge of $18.0 million was recorded during the quarter ended December 31, 2020 as a result of a decrease in the current quantities of recoverable proved and probable oil and natural gas reserves in the Company's Penny oil CGU. The estimated recoverable amount of this CGU as at December 31, 2020 was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator as at December 31, 2020 at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amount of the Penny oil CGU was determined using the FVLCD methodology. This methodology is based on what Tamarack estimates it could receive should the assets in this CGU be disposed of in the current environment taking into account lower forecasted oil and natural gas prices.

An impairment charge of $381.0 million was recorded as at March 31, 2020 as a result of a decrease in current and forecasted oil and natural gas prices. The impairment was recorded as follows: 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 estimated recoverable amount of these CGUs as at March 31, 2020 was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2019 and updated by the Company's internal reserves evaluator to March 31, 2020 for production; production costs; royalty costs; future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amount of the CGUs was determined using the FVLCD methodology. This methodology is based on what Tamarack estimates it could receive should the assets in these CGUs be disposed of in the current environment taking into account lower forecasted oil and natural gas prices.

The impairment charge of $381.0 million was allocated to property, plant and equipment in the amount $377.6 million and $3.4 million was allocated to the right-of-use assets.

The Company recorded an aggregate impairment charge of $399.0 million for the year ended December 31, 2020 of which $235.0 million related to the Viking oil CGU, $137.0 million related to the Cardium oil CGU, $25.0 million related to the Penny oil CGU, and $2.0 million related to the minor gas CGU. The aggregate impairment was allocated to property, plant and equipment in the amount of $395.6 million and $3.4 million was allocated to right-of-use.

Income Taxes

The Company did not incur any cash tax expense for the three months and year ended December 31, 2021 and does not expect to pay any cash tax until late 2022 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2021, a deferred income tax expense of approximately $51.0 million and $129.3 million, respectively, was recognized compared to a deferred income tax expense of $2.1 million and a deferred income tax recovery of $87.5 million for the same periods in 2020.

The following table outlines the Company's estimated tax pools as at December 31, 2021:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	32
Canadian development expense (CDE)	30%	375
Canadian oil and gas property expense (COGPE)	10%	351
Non-capital losses (NCL)	100%	123
Undepreciated capital cost (UCC)	25%	117
Share issue costs and other	various	6
Total		1,004

Adjusted Funds Flow and Net Income (Loss)

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands, except per share)	**2021**	2020	% change	**2021**	2020	% change
Cash flow from operating activities	**$118,647**	$23,859	397	**$297,894**	$125,290	138
Abandonment expenditures	**1,574**	1,271	24	**4,466**	3,825	17
Transaction costs	**–**	–	–	**8,110**	–	–
Changes in non-cash working capital	**3,859**	3,764	3	**29,789**	(6,367)	(568)
Adjusted funds flow (1)	**$124,080**	$28,894	329	**$340,259**	$122,748	177
Per share - basic (1)	**$0.31**	$0.13	138	**$0.96**	$0.55	75
Per share - diluted (1)	**$0.30**	$0.13	131	**$0.94**	$0.55	71
Net income (loss)	**$140,448**	$(18,220)	(871)	**$390,508**	$(311,384)	(225)
Per share - basic	**$ 0.35**	$(0.08)	(538)	**$ 1.10**	$(1.40)	(179)
Per share - diluted	**$ 0.34**	$(0.08)	(525)	**$ 1.08**	$(1.40)	(177)

(1) Capital Management Measure; See *"Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures"* Section of this MD&A.

Adjusted funds flow (see "Non-IFRS Financial Measures") and cash flow from operating activities for the three months and year ended December 31, 2021 were higher compared to the same periods in 2020. This was primarily due to an increase in revenue resulting from additional production due to acquisitions completed throughout 2021, higher commodity prices, partially offset by a realized hedging loss in 2021, higher production and transportation costs and higher royalty expense.

The Company recorded net income of $140.4 million ($0.35 per share basic and $0.34 per share diluted) and net income of $390.5 million ($1.10 per share basic and $1.08 per share diluted) during the three months and year ended December 31, 2021 compared to a net loss of $18.2 million ($0.08 per share basic and diluted) and a net loss of $311.4 million ($1.40 per share basic and diluted), respectively in the same periods in 2020.

The increase in net income for the three months ended December 31, 2021 as compared to the same period in 2020 is primarily due to an increase in revenue, an impairment reversal in Q4/21 versus impairment charge in Q4/20, and an increase in unrealized hedging gain, partially offset by an increase in realized hedging loss, higher royalty costs, higher production and transportation costs, higher general and administrative costs, higher interest on bank debt, higher depletion, depreciation and amortization costs and deferred income tax expense. The increases in revenue and royalty expense are largely attributable to the increase in the Company's production resulting from the acquisitions and higher commodity prices. The increase in all other expenses is largely attributable to the increase in the Company's production resulting from the acquisitions. Changes in the Company's realized and unrealized hedging is reflective of the impact of changes in commodity prices on the Company's risk management contracts in place as at that date.

The increase in net income for the year ended December 31, 2021 as compared to the same period in 2020 is primarily due to an increase in revenue, impairment reversals in 2021 versus impairment charges in 2020, and an increase in unrealized hedging gain, partially offset by higher royalty costs, higher realized hedging loss, higher production and transportation costs, higher general and administrative costs, higher acquisition related transaction costs, higher interest on bank debt, higher depletion, depreciation and amortization costs and deferred income tax expense. The increase in revenue and royalty expense are largely attributable to the increase in the Company's production resulting from the acquisitions and higher commodity prices. The increase in all other expenses is largely attributable to the increase in the Company's production resulting from the acquisitions. Changes in the Company's realized and unrealized hedging is reflective of the impact of changes in commodity prices on the Company's risk management contracts in place as at that date.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

Year-over-Year	Three months ended December 31,			Year ended December 31,		
($ thousands)	**2021**	2020	% change	**2021**	2020	% change
Land	**$2,480**	$40	6,100	**$9,065**	$3,385	168
Geological and geophysical	**140**	71	97	**543**	85	539
Drilling and completion	**30,212**	9,319	224	**136,692**	72,936	87
Equipment and facilities	**7,058**	2,697	162	**38,805**	23,553	65
Capitalized G&A	**1,667**	900	85	**5,037**	3,300	53
Office equipment	**115**	61	89	**1,017**	284	258
Total capital expenditures	**$41,672**	$13,088	218	**$191,159**	$103,543	85

During the fourth quarter of 2021, the Company drilled, completed and equipped, eleven (8.5 net) Clearwater oil wells, four (4.0 net) Charlie Lake oil wells, six (6.0 net) Viking oil wells and two (2.0 net) water source wells.

For the year ended December 31, 2021, the Company drilled, completed and equipped forty (40.0 net) Viking oil wells, forty-three (40.0 net) Clearwater oil wells, thirteen (13.0 net) Charlie Lake oil wells, eight (8.0 net) water source and injector wells and two (0.8 net) Falher gas wells.

Included in equipment and facilities expenditures for the year ended December 31, 2021 are expenditures of approximately $7.9 million related to the Company's Nipisi gas conservation project to eliminate the venting and incineration of solution gas into the atmosphere in furtherance of the Company's sustainability initiatives and reducing greenhouse gas emissions. Total estimated project capital spending is estimated to be approximately $11.9 million. In connection with this project the Company has recorded $5.2 million of combined Federal Government of Canada Emissions Reduction Fund ("ERF") and Province of Alberta Methane Technology Implementation Program ("MTIP") funding, of which $1.1 million is repayable under the terms of the ERF agreement. Total MTIP non-repayable government grant funding is estimated to be approximately $1.75 million. Total ERF government grant funding is estimated to be approximately $8.9 million, of which 65% is repayable under the terms of the ERF agreement., The ERF agreement includes scheduled repayments for the repayable funding of approximately $0.6 million on March 31, 2025, $1.9 million on March 31, 2026 and a final payment of $3.3 million on March 31, 2027. The repayable government loan funding will be interest-free based on the Company's compliance with the terms and conditions of the ERF funding agreement and all repayments made in accordance with the above noted repayment schedule.

For the Year ended December 31,2021 Drilling Summary		
	Gross	Net
Viking	40.0	40.0
Clearwater	43.0	40.0
Charlie Lake	13.0	13.0
Water source and injectors	8.0	8.0
Falher	2.0	0.8
	106.0	101.8

Acquisitions and Dispositions

2021 Acquisitions

On March 25, 2021 the Company completed the Northern Clearwater, Eyehill oil acquisition that included assets in both the Nipisi and Provost fields for total cash consideration of $102.6 million. There were $0.7 million of transaction costs incurred by the Company expensed through 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 Clearwater oil CGU (Nipisi) and the Viking oil CGU (Provost). Assets held for sale relate to the sale of a gross overriding royalty ("GORR") on the Northern Clearwater Nipisi assets.

The determination of the purchase price, based on management's 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 fair value of oil and natural gas interests 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%.

On March 25, 2021 the Company completed the Northern Clearwater oil acquisition of assets in the Nipisi field 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 common 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 sale of a GORR on the Northern Clearwater Nipisi 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**

The Company acquired all of the issued and outstanding common shares of Anegada Oil Corp. ("Anegada") on June 1, 2021 for total consideration of $538.4 million. The assets acquired from Anegada included certain oil and natural gas properties located in the Grande Prairie field in the Charlie Lake area. The acquisition was completed for total cash consideration of $258.2 million and the issuance of 105.3 million common shares of the Company at the date of closing share price of $2.66 per common share. 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 June 1, 2021. There were $7.4 million of transaction costs incurred by the Company and expensed through earnings. Assets acquired in this transaction will be included in the Charlie Lake oil CGU. Assets held for sale primarily relate to the sale of a GORR on the Charlie Lake (Grande Prairie) assets.

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

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	677,740
Right-of-use assets		1,624
Current assets		21,097
Current liabilities		(10,451)
Lease liabilities		(1,624)
Risk management contracts		(9,610)
Bank debt		(37,734)
Assets held for sale		33,078
Decommissioning obligations		(6,072)
Deferred tax liability		(129,638)
Net assets acquired	**$**	**538,410**
Purchase consideration:		
Cash	$	258,201
Share consideration (105,341,880 common shares)		280,209
Total purchase consideration	**$**	**538,410**

For purposes of estimating the acquisition-date fair value of the oil and natural gas interests, the Company's internal reserves evaluator provided an estimate of proved and probable oil and natural gas reserves and the related cash flows. 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%.

On August 31, 2021 the Company completed the Southern Clearwater oil acquisition of assets in the Jarvie field for total cash consideration of $35.7 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.

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	$	37,039
Decommissioning obligations		(1,312)
Net assets acquired	**$**	**35,727**
Purchase consideration:		
Cash consideration	$	35,727
Total purchase consideration	**$**	**35,727**

Other minor acquisitions

For the year ended December 31, 2021 the Company executed other minor acquisitions in various CGUs and various fields for cash consideration of approximately $25.4 million.

2021 Dispositions

On September 9, 2021, Tamarack completed a non-cash asset swap transaction whereby the Company disposed of certain oil properties located in the Lochend and Harmattan areas of Alberta (Cardium oil CGU), and acquired certain oil properties in the Monarch area of Alberta (Penny oil CGU).The carrying value of the Lochend and Harmattan assets disposed, net of decommissioning obligations, was $6.9 million and the fair value of the Monarch net assets acquired was $7.8 million, resulting in a gain on the exchange of $0.9 million.

For the year ended December 31, 2021 the Company disposed of a 4% GORR on a select portion of the Northern Clearwater area (Nipisi field) properties for net proceeds of $13.5 million and recorded a gain on disposition of $7.5 million. The Company also disposed of a 2% GORR on a select portion of the Charlie Lake area (Grande Prairie field) properties for net proceeds of $31.6 million. The Company also disposed of non-core properties for proceeds of $1.2 million and recorded a gain on disposition of $0.3 million.

Share Capital

		2021		2020
($ thousands)	Number	Amount	Number	Amount
Balance, January 1	262,776,395	$876,124	222,793,117	$832,799
Issue of common shares - cash	33,333,300	75,000	40,925,000	47,064
Issue of common shares - acquisitions	110,230,769	290,427	–	–
Issue of common shares - cash on stock options	481,667	1,623	–	–
Issue of common shares - RSU and PSU exercise	4,047,343	–	3,363,378	–
Issue on settlement of preferred shares	307,025	1,104	–	–
Purchase of common shares - cancellation	–	–	(664,100)	(2,551)
Purchase of common shares - RSU and PSU exercise	(4,238,400)	–	(3,641,000)	–
Transfer on stock option exercise	–	1,023	–	–
Share issue costs, net of tax (2021 - $864; 2020 - $368)	–	(2,909)	–	(1,188)
Balance, December 31	406,938,099	$1,242,392	262,776,395	$876,124

(thousands)	March 3, 2022	December 31, 2021	December 31, 2020
Common shares outstanding	**431,323**	406,938	262,776
Common shares held in treasury	**2,370**	938	747
Options outstanding	**1,932**	2,142	1,904
RSUs outstanding	**4,428**	4,703	5,365
PSUs outstanding	**4,909**	4,874	3,564

At December 31, 2021, there are no (December 31, 2020 – 740,307) preferred shares of Tamarack Acquisition Corp. (the “TAC Preferred Shares”) issued and outstanding. The Company settled the TAC Preferred Shares by issuing 307,025 Common Shares and a payment of $0.1 million during the fourth quarter of 2021 in connection with the amalgamation of Tamarack Acquisition Corp. into Tamarack Valley Energy Ltd. on January 1, 2022.

On February 15, 2022, the Company issued 26,298,396 Common shares as partial consideration in connection with the acquisition of Crestwynd Exploration Ltd.

Liquidity and Capital Resources

($ thousands)	**December 31, 2021**	December 31, 2020
Working capital deficiency (surplus) (1)	**$(15,253)**	$8,454
Other liability	**1,100**	–
Bank debt	**477,437**	210,857
Net debt (1)	**463,284**	219,311
Quarterly adjusted funds flow (1)	**$124,080**	$28,894
Annualized factor	**4**	4
Annualized adjusted funds flow (1)	**496,320**	115,576
Net debt to annualized adjusted funds flow (1)	**0.9x**	1.9x

(1) Capital Management Measure; *See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures"* Section of this MD&A.

Despite the improvement in commodity prices during 2021, 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. The Company generally relies on adjusted funds flow and its credit facility to fund its capital requirements, dividend payments and provide liquidity.

Tamarack's net debt, including working capital deficiency (surplus) (see "Capital Management Measures"), totaled $463.3 million as at December 31, 2021. This compares to the Company's net debt of $519.7 million as at September 30, 2021 and $219.3 million as at December 31, 2020. Tamarack's Q4/21 net debt to annualized adjusted funds flow ratio (see "Capital Management Measures") was 0.9 times.

The Company's $58.7 million investment in capital additions and acquisitions during Q4/21 was fully funded by Tamarack's adjusted funds flow (see "Capital Management Measures") of $124.1 million. The Company also reduced net debt by $56.4 million as compared to Q3/21.

The Company believes that available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's 2022 development capital program and dividend payments for the 2022 fiscal year.

The Company announced on November 1, 2021 that the Toronto Stock Exchange had accepted the Company's intention to recommence the NCIB that was previously suspended on April 7, 2020. Pursuant to the NCIB, the Company is permitted to purchase up to 20.4 million Common Shares over a period of twelve months commencing on November 3, 2021. During the year ended December 31, 2021, the Company did not purchase and cancel any Common shares.

During the year ended December 31, 2020, the Company purchased and cancelled 0.7 million Common Shares at an average price of $1.94 per Common Share, for a total repurchase cost of $1.3 million.

On February 15, 2022 the Company paid its inaugural monthly cash dividend on its common shares of $0.0083 per share to shareholders of record at the close of business on January 31, 2022.

Bank Debt

Tamarack currently has available a Sustainability Linked Lending revolving credit facility in the amount of $550 million and an operating facility of $50 million (collectively, the “SLL Facility”) with a syndicate of lenders.

The Company’s existing credit facility was amended to include sustainability-linked incentive pricing terms in the recently completed SLL Facility Amended and Restated Credit Agreement (“ARCA”). Additionally, the ARCA eliminated the term credit facility and the Consolidated Net Debt to Cash Flow Ratio financial covenant, and added a Consolidated Senior Debt-to-Consolidated EBITDA ratio interest rate determination.

The total interest rate on the SLL Facility is determined through a pricing grid that categorizes based on both a total amount drawn and a Consolidated Senior Debt-to-Consolidated EBITDA Ratio as defined in the SLL Facility ARCA. The interest rate will vary depending on: the lending vehicle employed; the total loan value drawn; and the Company’s Consolidated Senior Debt-to-Consolidated EBITDA ratio. The ARCA defines: (i) Consolidated Senior Debt to Consolidated EBITDA Ratio as the ratio of Consolidated Senior Debt at the end of the Fiscal Quarter to Consolidated EBITDA for the Consolidated EBITDA period; (ii) Consolidated Senior Debt as Consolidated Debt; and (iii) Consolidated EBITDA as determined in accordance with IFRS as Net Income plus interest expense, plus the provision for income taxes, plus or minus all non-cash items, plus one-time transaction costs and fees relating to acquisitions, dispositions, equity offerings and other similar transactions, plus or minus losses and or gains from asset sales, plus or minus losses or earnings attributable to extraordinary and non-recurring items and less any cash payments related to prior periods included or deducted in determining Net Income. The Consolidated EBITDA period as at December 31, 2021 is the most recent quarter annualized.

Interest on bankers’ acceptances (“BA”) and LIBOR (or LIBOR Benchmark Replacement) based loans (“LIBOR”) will vary based on a BA/LIBOR pricing grid from a low of the banks’ posted rates plus 2.75% to a high of the banks’ posted rates plus 4.75%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks’ prime rates plus 1.75% to a high of the banks’ prime rates plus 3.75%. The standby fee for the SLL Facility will vary as per a pricing grid from a low of 0.69% to a high of 1.19% on the undrawn portion of the SLL Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates.

The LIBOR benchmark transition begins on December 31, 2021 with certain tenors of the U.S. dollar LIBOR benchmark no longer published as of that date. Certain other tenors will continue to be published through mid-2023. As per the ARCA the LIBOR benchmark will be replaced by the secured overnight financing rate (“SOFR”) as published by the Federal Reserve Bank of New York. We do not expect this change to have a material impact to Tamarack under the SLL Facility as U.S. dollar borrowings under the SLL facility can also bear interest at the banks’ U.S. prime rates.

The SLL Facility incorporates sustainability-linked incentive pricing terms. The SLL Facility incorporates three of Tamarack’s long-term goals as key performance indicators (“KPIs”) and has structured them into sustainability performance targets (“SPTs”), that will decrease Tamarack’s cost of borrowing by up to five basis points if the SPTs are achieved or increase Tamarack’s cost of borrowing by up to five basis points in the event SPTs are missed. The SPTs include:

- Greenhouse Gas Emissions Intensity: 40% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline, with a significant decrease in 2021 and more ratable 5% decreases through 2022 to 2025. This SPT exceeds the previous set target due to 2021 acquisitions and positive progress in emissions reductions to date.
- Decommissioning Management: committed annual capital investment in abandonment, remediation and reclamation activities at 150% of the Alberta Energy Regulator inventory reduction voluntary closure program targets. This target is equivalent to ~4.33% of inactive liabilities in 2021 with a 5% annual escalation.

- Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025 with annual milestones and minimum of two additions each year.

As at December 31, 2021, the SLL Facility was secured by a $1.2 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the SLL 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.

A total of $477.4 million was drawn as of December 31, 2021 (December 31, 2020 – $210.9 million). The interest rate applicable to the drawn amounts as of this date was 3.37%. The SLL Facility will be subject to its next extension by May 31, 2022, and if not extended by that date, will cease to revolve and all outstanding balances will become repayable one year from that date.

The Company manages its SLL Facility using a combination of prime rate loans, BA notes and US dollar denominated LIBOR (or LIBOR Benchmark Replacement) loans. During the quarter ended December 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 December 31, 2021, the Company had drawn US$235.0 million, fixed at notional amounts of $297.5 million through CCS maturing across the month of January 2022 (December 31, 2020 – the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS).

On February 10, 2022 the Company issued $200 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 (the "Notes"). The notes were offered through a private placement underwriting agreement entered into on February 2, 2022. The Notes are issued at par under a trust indenture and are general unsecured obligations of Tamarack ranking pari passu with all of the Company's existing and future senior unsecured indebtedness. The Notes are being issued in accordance with the Company's Sustainability-Linked Bond Framework.

Commitments

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

($ thousands)	2022	2023	2024	2025	2026+
Bank debt(1)	–	477,437	–	–	–
Lease(2)	328	347	347	261	–
Government loan(3)	–	–	–	471	629
Take or pay commitments(4)	4,023	3,894	–	–	–
Processing commitments(5)	4,578	4,689	4,769	4,088	21,464
Gas transportation(6)	4,876	3,590	313	11	–
Capital commitments(7)	42,971	57,843	–	–	–
Total	56,776	547,800	5,429	4,831	22,093

(1) If not extended by May 31, 2022, the SLL Facility will cease to revolve and all outstanding balances will become repayable May 31, 2023.

(2) Relates to the variable operating costs, which are a non-lease component of the Company's head office sublease and sublease expansion. The Tamarack head office sublease and sublease expansion expire on September 30, 2025.

(3) Relates to the scheduled payments on the repayable government loan funding receivable from the government of Canada under the terms of the ERF agreement signed by the Company related to the Nipisi gas conservation program.

(4) 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.

(5) Processing commitments to guarantee firm capacity in various facilities.

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

(7) Initial commitment of $200.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to December 31, 2023 of which $100.8 is remaining to be incurred.

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 consolidated financial statements.

Unit Cost Calculation

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

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
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 Financial Measures, Non-IFRS Financial Ratios, and Capital Management Measures

This document contains the terms "net production expenses", "operating netback" and "operating field netback", which are non-IFRS financial measures, or ratios. The Company uses these measures to help evaluate Tamarack's performance. These non-IFRS financial measures and ratios do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. This document also contains the capital management measures of "quarterly adjusted funds flow", "net debt", "working capital deficiency (surplus)", "net debt to annualized adjusted funds flow", and "year-end net debt to trailing annual adjusted funds flow".

(a) **Quarterly Adjusted Funds Flow (Capital Management Measure)** - Quarterly adjusted funds flow is calculated by taking cash-flow from operating activities on a quarterly basis and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs 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, pay dividends and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income (loss) per share. The calculation of the Company's adjusted funds flows is summarized starting on page 15 in the section titled "Adjusted Funds Flow and Net Income (Loss)".

(b) **Net Production Expenses, Operating Netback and Operating Field Netback (Non-IFRS Financial Measures, and Non-IFRS Financial Ratios if calculated on a per boe basis)** - 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 and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense and can also be calculated on a per boe basis, which results in them being considered a non-IFRS financial ratio. 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 11 in the section titled "Operating Netback".

(c) **Net Debt and Working Capital Deficiency (Surplus) (Capital Management Measure)** - 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, plus other liability 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)	December 31, 2021	December 31, 2020
Accounts payable and accrued liabilities	**$72,188**	$38,903
Cross currency swap liability	**292**	1,597
Accounts receivable	**(79,904)**	(30,781)
Prepaid expenses and deposits	**(7,829)**	(1,265)
Working capital deficiency (surplus)	**(15,253)**	8,454
Other liability	**1,100**	–
Bank debt	**477,437**	210,857
Net debt	**$463,284**	$219,311

(d) **Net Debt to Annualized Adjusted Funds Flow (Capital Management Measures)** - 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 fund capital requirements, dividend payments, pay off debt and take on new debt, if necessary, using the most recent quarter's results. The calculation of the Company's net debt to annualized adjusted funds flow can be seen starting on page 21 in the section titled "Liquidity and Capital Resources".

(e) **Year-end Net Debt to Trailing Annual Adjusted Funds Flow (Capital Management Measure)** - Management uses certain industry benchmarks, such as net debt to trailing annual adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated as estimated year-end net debt divided by the estimated adjusted funds flow for the four preceding quarters at year-end.

(f) **Free Funds Flow (Capital Management Measure)** - Management uses certain industry benchmarks, such as free 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 funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

Year-over-Year ($thousands)	Three months ended December 31,			Year ended December 31,		
	2021	2020	% change	**2021**	2020	% change
Adjusted funds flow	**$124,080**	$28,894	329	**$340,259**	$122,748	177
Less: capital expenditures	**41,672**	13,088	218	**191,159**	103,543	85
Free funds flow	**$82,408**	$15,806	421	**$149,100**	$19,205	676

Selected Quarterly Information

Three months ended	**Dec. 31, 2021**	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2020	Sep. 30, 2020	Jun. 30, 2020	Mar. 31, 2020
Sales volumes								
Natural gas ***(mcf/d)***	**74,291**	72,935	60,887	52,466	53,738	53,420	49,610	52,912
Oil and NGL ***(bbls/d)***	**28,002**	29,100	22,268	15,194	13,093	12,630	12,729	14,712
Average boe/d ***(6:1)***	**40,384**	41,256	32,416	23,938	22,049	21,533	20,997	23,531
Product prices								
Natural gas ***($/mcf)***	**5.09**	3.44	2.77	3.15	2.46	1.61	1.37	1.61
Oil and NGL ***($/bbl)***	**80.55**	70.40	67.47	56.91	43.22	42.69	23.40	43.41
Oil equivalent ***($/boe)***	**65.21**	55.73	51.55	43.03	31.67	29.02	17.42	30.76
(000s, except per share amounts)								
Financial results								
Gross revenues	**242,288**	211,527	152,061	92,696	64,238	57,491	33,295	65,872
Cash provided by operating activities	**118,647**	100,558	40,253	38,436	23,859	26,965	28,107	46,359
Adjusted funds flow [(2)]	**124,080**	102,486	71,741	41,236	28,894	30,837	20,972	42,045
Per share – basic	**0.31**	0.25	0.21	0.16	0.13	0.14	0.09	0.19
Per share – diluted	**0.30**	0.25	0.21	0.16	0.13	0.14	0.09	0.19
Net income (loss)	**140,448**	20,032	230,194	(166)	(18,220)	(5,776)	(36,067)	(251,321)
Per share – basic	**0.35**	0.05	0.69	(0.00)	(0.08)	(0.03)	(0.16)	(1.13)
Per share – diluted	**0.34**	0.05	0.67	(0.00)	(0.08)	(0.03)	(0.16)	(1.13)
Capital expenditures	**41,672**	69,978	30,805	48,704	13,088	10,364	6,218	73,873
Acquisitions[(1)]	**22,593**	52,004	539,506	147,187	94,684	4,127	–	–
Dispositions[(1)]	**(74)**	(8,140)	(32,283)	(13,884)	(15,525)	–	–	–
Total assets	**2,328,153**	2,230,382	2,180,303	1,199,743	1,027,600	963,220	935,892	984,045
Net debt[(2)]	**463,284**	519,708	505,992	286,175	219,311	199,561	213,066	227,151
Bank debt	**477,437**	520,961	520,012	270,810	210,857	198,994	206,467	209,423
Decommissioning obligations	**284,472**	265,929	264,791	242,692	245,437	241,047	198,485	186,816

(1) Includes cash and non-cash consideration.

(2) Capital Management Measure; *See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures"* Section of this MD&A.

Selected Annual Information

	2021	2020	2019
Sales volumes			
Natural gas *(mcf/d)*	**65,226**	52,426	53,444
Oil and NGL *(bbls/d)*	**23,691**	13,289	15,165
Average boe/d *(6:1)*	**34,562**	22,027	24,072
Product prices			
Natural gas *($/mcf)*	**3.70**	1.77	2.06
Oil and NGL *($/bbl)*	**70.60**	38.42	61.58
Oil equivalent *($/boe)*	**55.38**	27.40	43.37
(000s, except per share amounts)			
Financial Results			
Gross revenues	**698,572**	220,896	381,066
Net income (loss)	**390,508**	(311,384)	(39,011)
Per share – basic	**1.10**	(1.40)	(0.17)
Per share – diluted	**1.08**	(1.40)	(0.17)
Capital expenditures	**191,159**	103,543	178,966
Acquisitions(1)	**761,290**	98,811	9,942
Dispositions(1)	**(54,381)**	(15,525)	–
Total assets	**2,328,153**	1,027,600	1,247,119
Net debt(2)	**463,284**	219,311	189,481
Bank debt	**477,437**	210,857	192,907

(1) Includes cash and non-cash consideration.

(2) Capital Management Measure; *See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures"* Section of this MD&A.

Significant factors and trends that have impacted the Company's results during both the above Quarterly and Annual 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 June 1, 2021, Tamarack closed the acquisition of Charlie Lake area properties in the Grande Prairie field of Alberta. The assets include approximately 11,800 boe/d of oil weighted assets, along with adding 349.7 net sections in the Charlie Lake oil play of Alberta for a total purchase price of approximately $538.4 million.
- On March 25, 2021, Tamarack closed two separate agreements to acquire assets in the Northern Clearwater and Eyehill areas in the Provost and Nipisi fields of Alberta. The assets include approximately 2,800 boe/d of low decline (~16%) oil weighted assets under waterflood, along with adding approximately 38,400 net acres in the Northern 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 Northern and Southern Clearwater areas in the Nipisi and Jarvie fields of Alberta. The assets include approximately 2,000 bbls/d of crude oil production in the Northern and Southern Clearwater oil plays 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.
- The Company recorded an impairment reversal in Q4/21 in the amount of $90.0 million on the Viking oil CGU, Cardium oil CGU and Penny oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed $52.3 million, the Cardium oil CGU reversed $14.3 million and the Penny oil CGU reversed $23.4 million.
- The Company recorded an impairment reversal in Q2/21 in the amount of $300.0 million on the Viking oil CGU and Cardium oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed $160.0 million and the Cardium oil CGU reversed $140.0 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.

Significant factors and trends that have impacted the Company's results for the above Annual period include:

- In Q4/19, the Company recorded an impairment charge on its Cardium oil CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to decreased current and forecasted natural gas prices in the amount of $68.0 million.

Critical Accounting Estimates

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

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

(b) **Carrying value of property, plant and equipment ("PP&E")** – PP&E is measured at cost less accumulated depletion, depreciation, amortization, impairment losses and impairment reversals. 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 costs, forecasted royalty costs and forecasted future development costs and the impact on the financial statements of future periods could be material.

The Company has considered the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources in its assessment of impairment and impairment reversal on its oil and gas properties, both as indicators of impairment and impairment reversal, and in the estimates and judgments involved in testing for impairment and impairment reversal. The estimated recoverable amount of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 20 years. However, the ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain. The Company will continue to monitor its estimates as the global demand for alternative energy sources continues to evolve.

(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 judgments 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 oil and natural gas interests (included in property, plant and equipment). The determination of the acquisition-date fair value of oil and natural gas interests involves significant estimates, including the estimate of proved and probable oil and natural gas reserves and the related cash flows and the discount rates. The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs and forecasted future development costs. The estimates of proved and probable oil and natural gas reserves and the related cash flows are prepared by the Company's external independent qualified reserves evaluator or internal reserves evaluator.

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 December 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 December 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, 2021.

(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, and outbreaks of variant strains of the virus. 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 social and travel restrictions and business disruptions; the severity of the disease; the effectiveness of actions taken to contain the virus and treat the disease, including access to effective vaccines, domestic and global vaccination rates; and the ability of business to resume regular operations. To the extent that the COVID-19 pandemic continues to adversely affect 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, 2021.

(b) Continued Volatility in Commodity and Petroleum Products Prices

Tamarack's financial performance is significantly dependent on the prevailing prices of crude oil, refined products and natural gas. Crude oil prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand; global economic conditions including factors impacting global trade and disruption of trade routes; the actions of OPEC and other non-OPEC oil exporting nations, including, but not limited to, compliance or non-compliance with production quotas agreed upon by OPEC members or decisions by OPEC not to impose production quotas on its members; development, adoption, pricing and availability of alternate sources of energy; actions of domestic and foreign governments, regulatory bodies and quasi-regulatory bodies that may impact commodity prices; enforcement of environmental or emissions regulations; public sentiment towards the use of fossil fuels, including crude oil; political stability and social conditions in oil-producing countries; outbreak of war;

market access constraints and transportation interruptions (pipeline, marine or rail); outbreak or continuation of a pandemic; terrorist threats; technological developments; the occurrence of natural disasters; and weather conditions.

In the first half of 2020, the price of oil and other petroleum products deteriorated significantly as a result of the rapid spread of the COVID-19 pandemic. Commodity prices remained under pressure throughout 2020, and into the first half of 2021, with additional crude oil supply coming on-stream as a result of actions taken by OPEC and non-OPEC oil and gas exporting countries to set and maintain increased production levels, causing increased volatility in commodity prices. Since the second half of 2021, the crude oil market has responded positively as the OPEC+ alliance unwinds cuts as part of the output recovery scheme in conjunction with a gradual global economic recovery from the COVID-19 pandemic; however, the potential for volatility in crude oil demand and supply remains. 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", price volatility 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.

The 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. While the recovery in oil demand as a result of the easing of COVID-19 restrictions, combined with a prudent supply policy implemented by the OPEC+ alliance, has resulted in crude oil prices recovering to pre-pandemic levels, the extent and duration of this recovery remains uncertain. 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 market conditions and the potential for decreased 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.

(c) Environmental and Climate Change Risk

As a result of growing international concern in respect of climate change, Tamarack has seen a significant increase in focus on the transition to alternative, lower-carbon energy sources. Governments, financial institutions, insurance companies, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to develop and implement, among other things, regulatory and policy changes, changes in investment strategies and habits, and a restructuring of energy consumption profiles, which, individually and collectively are intended to or have the effect of accelerating the transition to less carbon-intensive energy sources and the reduction in global consumption of fossil fuels. Overall, Tamarack is not able to estimate at this time the degree to which climate change related consumer behaviour, regulatory, climatic conditions, and climate-related transition risks could impact the Company's business, financial condition and results of operations.

Climate change may have actual or perceived adverse impacts on the Company's operations, business, and financial results, including an increase in the frequency of extreme climatic conditions. Weather and climate affect demand for crude oil and gas, and therefore, the predictability of weather and climate affects the Company's ability to accurately forecast supply and demand. In addition, the Company's operations, including exploration, production and construction operations, and the operations of major customers, suppliers and service providers, can be affected by acute and chronic physical climate risks, such as floods, forest fires, earthquakes, hurricanes, landslides, mudslides, and other extreme weather events, natural disasters or long-term shifts in weather patterns. This may result in cessation or diminishment of production, delay of exploration and development activities or delay in executing the Company's capital expenditure plans, which may require the Company to adopt increased or additional mitigation requirements

Growing concerns over climate change have also led to an increase in climate and environment-centric disputes and litigation in various jurisdictions, including at a Federal and Provincial level, alleging various claims and registering complaints, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many such climate change related actions are in preliminary stages of litigation, and in some cases raise novel or untested issues and causes of action, the risk that legal, societal, scientific and political developments will increase the likelihood of successful climate change related litigation against energy producers remains uncertain. The outcome and ramifications of any such litigation is uncertain and may materially impact the Company's business, financial condition or results of operations. The Company may also be subject to negative or damaging publicity associated with such matters, which may adversely affect the public sentiment and the Company's reputation, regardless of whether the Company is ultimately found responsible for claims alleged. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

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, safety, and public disclosure and reporting 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.

The ISSB is expected to develop globally consistent, comparable and reliable standards for disclosing and reporting ESG and climate-related metrics. As at December 31, 2021, the ISSB has not issued any new sustainability disclosure standards or exposure drafts. In addition, the Canadian Securities Administrators have issued a proposed NI 51-107 Disclosure of Climate-related Matters. The cost to implement and comply with these standards, and others, that may be developed or evolved over time, has not yet been quantified.

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:

- the intentions of management and the Company;
- the Company's commitment to maintaining financial flexibility and liquidity;
- the Company's business strategy, objectives, strength and focus, including with respect to acquisitions;
- the effects of the Company's acquisitions on the Company's strategy, land holdings and profitability, including, but not limited to, the Anegada acquisition, the Crestwynd acquisition, and the various acquisitions of Northern and Southern Clearwater assets;
- the implementation of the Nipisi gas conservation project and the objectives thereof;
- 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, including the Company's capital expenditure plans, and the oil and gas industry in general;
- uncertainty regarding the full impact of COVID-19 on global economies, oil demand and commodity prices, and the timing of full economic recovery related to the COVID-19 pandemic;
- applications and grants under the Canada Emergency Wage Subsidy ("**CEWS**"), Alberta Site Rehabilitation Program ("**SRP**"), Saskatchewan Accelerated Site Closure Program ("**ASCP**") programs, the Federal Emissions Reduction Fund ("**ERF**"), the Alberta Methane Technology Information Program ("**MTIP**"), including estimates of expected funding, and repayment timing thereof, as applicable;
- the Company's commitment to advancing ESG practices, managing greenhouse gas emissions and to continued Indigenous and community partnerships in the areas where it operates;
- the potential impact of ESG disclosure and reporting policies and standards imposed by the ISSB and proposed NI 51-107;
- expectations regarding the estimated recoverable amount of the Company's oil and gas properties, royalty rates as a percentage of revenue, and committed capital spending to develop the GORR lands and timing thereof;
- expectations relating to future realized commodity prices, volatile commodity prices, royalty rates and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing;
- the Company's diversification strategy, including the Company's third-party gas sales contracts, and the effects thereof on risk mitigation, price exposure and realized price improvements;
- the Company's financial and physical hedging program, including the use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates, and interest rates, and the effects thereof on cash flow risk and commodity pricing upside;
- any purchases under the NCIB program;
- the Company's plans in respect of returns of capital, including base dividend and enhanced return programs;
- expectations regarding the Company's ability to satisfy its 2022 development capital program and dividend payments for the 2022 fiscal year through available credit facilities combined with anticipated adjusted funds flow;
- the availability, size, terms, use and renewal of the Company's SLL Facility, including the various lending vehicles used by the Company from time to time, and the terms thereof;
- the projected impact of the LIBOR benchmark transition on the Company under the SLL Facility;
- management's expectations regarding the Company's ability to conform to its financial covenants;
- expectations relating to cash tax, tax pools, and deferred tax assets, including in respect of deferred income tax;

- future RSU and PSU settlements;
- the Company's head office sublease, as amended or extended, and the terms thereof;
- contractual obligations and commitments;
- estimates used to calculate decommissioning obligations and depletion of PP&E; and
- expectations regarding the merits and the outcome of ongoing litigation.

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 expenses;
- estimated proved and probable oil and natural gas reserves;
- the effects of heavy volume apportionment and fluctuating diluent costs on the heavy oil market in Alberta;
- 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 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;
- 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;
- Tamarack's ability to execute its plans in response to the COVID-19 pandemic; and
- The impact of inflation on costs.

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 Financial Measures”, “Critical Accounting Estimates”, “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 “Operational and Financial Highlights”, “COVID-19 Response”, “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”)”, “Impairment (Impairment Reversal) of Property, Plant and Equipment”, “Income Taxes”, “Adjusted Funds Flow and Net Income (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;
- increased borrowing costs due to increased lending rates from prime rate increase, negative changes to financial metrics evaluated under Sustainable Credit Facility sustainability performance targets and/or decreased ESG performance as determined by a third-party rating agency;
- 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 costs, transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources;
- changes in tax, royalty and environmental legislation and any government policy;
- any legal proceedings, the results thereof and the impact on the Company’s business, financial condition and results of operations;
- changes in the political landscape, both domestically and abroad; and
- increased operating and capital costs due to inflationary pressures (actual and anticipated).

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, 2021 , which may be accessed on Tamarack's SEDAR profile 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 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 Financial Measures, Non-IFRS Financial Ratios, and Capital Management Measures", and should not be used for purposes other than those for which it is disclosed herein. Tamarack and its management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, Tamarack's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future activities or results.

The forward-looking statements and FOFI contained in this MD&A, as defined by Canadian securities legislation, 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.