MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three and nine months ended September 30, 2021 and 2020. This MD&A is dated and based on information available as at October 27, 2021 and should be read in conjunction with the unaudited condensed consolidated interim financial statements ("financial statements") and the notes thereto for the three and nine months ended September 30, 2021 and 2020 and the audited consolidated financial statements for the year ended December 31, 2020. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2020, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The financial statements have been prepared in accordance with International Accounting Standards 34 "Interim Financial Reporting". The Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Measures" beginning on page 21. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Operational and Financial Highlights

- Achieved quarterly production volumes of 41,256 boe/d in Q3/21, representing a 92% increase compared to the same period in 2020.
- Generated adjusted funds flow (see "Non-IFRS Measures") of $102.5 million in Q3/21 ($0.25 per share basic and diluted) compared to $30.8 million in the same period in 2020 ($0.14 per share basic and diluted) and $216.2 million for the nine months ended September 30, 2021 ($0.64 per share basic and $0.63 per share diluted) compared to $93.9 million in the same period in 2020 ($0.42 per share basic and diluted).
- Generated free funds flow (see "Non-IFRS Measures"), excluding acquisition expenditures, of $32.5 million and net income of $20.0 million during the quarter.
- Invested $70.0 million in exploration and development ("E&D") capital expenditures, excluding acquisition expenditures, during the third quarter of 2021. This contributed to the drilling of 3 (3.0 net) Viking oil wells, 8 (8.0 net) Clearwater oil wells and 7 (7.0 net) Charlie Lake oil wells along with the investment in the Nipisi Clearwater gas conservation project, which currently is conserving 2.0 mmcf/d of natural gas and other Clearwater infrastructure initiatives.
- Exited the third quarter with $519.7 million of net debt (see "Non-IFRS Measures"); with a forecasted year end 2021 net debt to Q4/21 annualized adjusted funds flow (see "Non-IFRS Measures") of less than 1.2x.
- Successfully executed on further tuck-in acquisitions in the Clearwater oil and Charlie Lake light oil

plays for approximately $42.9 million. These acquisitions further our strategy of both adding to and enhancing the resiliency of our drilling inventory and free funds flow profile.

Dividend Policy and Return of Capital Framework

Tamarack is pleased to announce the implementation of its dividend policy and return of capital framework. The free funds flow return will be achieved through modest, sustainable base dividend growth, special dividends and tactical share buybacks.

- Sustainable Base Dividend – Providing shareholders with a sustainable base monthly dividend which grows in conjunction with earnings over time is a key focus for the Company. Tamarack will initiate a base dividend of up to 25% of free funds flow predicated on the Tamarack 5-year plan price deck of US$55/bbl WTI and $2.50/GJ AECO. The remainder of free funds flow will primarily be allocated to net debt reduction and strategic asset acquisitions in existing core areas.
- Enhanced Return to Shareholders – Once the Company reaches its long term $250 to $300 million net debt target, Tamarack plans to return up to 50% of the previous quarter's free funds flow inclusive of base dividends, taking into consideration market conditions, to its shareholders through tactical share buybacks and/or special dividends. The long-term debt target is predicated on a forecasted year-end net debt to trailing annual adjusted funds flow of 1.0x at US$45/bbl WTI. The remaining 50% of free funds flow will be allocated to further debt repayment and future acquisitions.

The inaugural monthly dividend of $0.0083 per share will be payable on February 15, 2022, to holders of common shares of the Company of record at the close of business on January 31, 2022. The base dividend is modelled to be sustainable down to less than US$35/bbl WTI.

Strategic and opportunistic M&A remains a key focus for Tamarack in enhancing and growing the sustainable free funds flow for the Company and shareholders. The Company will continue to execute potential M&A in a disciplined manner with a focus on free funds flow breakeven levels and debt adjusted free funds flow per share accretion within our five-year plan.

COVID-19 Response

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 and vaccine rollout, changes in social and travel restrictions and businesses resuming regular operations. The crude oil market, as evidenced by the increases in benchmark crude oil pricing, has responded positively as the OPEC+ alliance unwinds production cuts as part of the output recovery scheme in conjunction with the global economic recovery, but the potential for volatility in crude oil demand and supply remains. 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 for the remainder of 2021 and beyond. The Company has improved our flexibility and responsiveness by establishing capabilities and procedures for remote working and opening our corporate head office on a limited and intermittent basis during the nine months ended September 30, 2021. Tamarack remains committed to ensuring the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate, going above and beyond both Provincial and Federal government protocols.

Sustainability

Tamarack continues to be committed to advancing our environmental, social and governance ("ESG") practices as outlined in our inaugural Sustainability Report published in the third quarter of 2020. This report provides details on the Company's approach to sustainability, including our commitment to greenhouse gas emissions management and to continued Indigenous and community partnerships in the areas where Tamarack operates. In addition, the report highlights specific, measurable goals and targets related to key focus areas set by the Company. Tamarack will be releasing an updated Sustainability Report in the fourth quarter of 2021.

Production

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
	2021	2020	% change	**2021**	2020	% change
Production						
Light oil (bbls/d)	**19,405**	10,309	88	**14,720**	11,424	29
Heavy oil (bbls/d)	**5,438**	159	3,320	**4,275**	165	2,491
Natural gas liquids (bbls/d)	**4,257**	2,162	97	**3,243**	1,766	84
Natural gas (mcf/d)	**72,935**	53,420	37	**62,171**	51,986	20
Total (boe/d)	**41,256**	21,533	92	**32,600**	22,019	48
Percentage of oil and NGL	**71%**	59%	20	**68%**	61%	11

Average production for both Q3/21 and the nine months ended September 30, 2021 increased 92% and 48%, respectively, compared to the same periods in 2020 due to the West Central Acquisition that closed in July 2020, the Clearwater acquisitions ("Clearwater Acquisitions") that closed in December 2020, the Provost and Nipisi acquisitions that closed in March 2021 ("Provost and Nipisi Acquisitions"), the Anegada Acquisition that closed in June 2021, the Southern Clearwater Acquisition that closed in August 2021 (collectively the "Acquisitions") and the 2021 development programs, partially offset by expected declines of existing base production. The Company's oil and NGL weighting for Q3/21 and the nine months ended September 30, 2021 is 20% and 11% higher, respectively, as compared to the same periods in 2020.

Petroleum and Natural Gas Sales

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
	2021	2020	% change	**2021**	2020	% change
Revenue ($ thousands)						
Light oil	**$141,288**	$44,352	219	**$299,164**	$123,894	141
Heavy oil	**34,005**	560	5,972	**71,651**	1,593	4,398
Natural gas liquids	**13,184**	4,689	181	**32,198**	9,333	245
Natural gas	**23,050**	7,890	192	**53,271**	21,838	144
Total	**$211,527**	$57,491	268	**$456,284**	$156,658	191
Average realized price:						
Light oil ($/bbl)	**79.12**	46.77	69	**74.43**	39.58	88
Heavy oil ($/bbl)	**67.97**	38.31	77	**61.40**	35.27	74
Natural gas liquids ($/bbl)	**33.67**	23.57	43	**36.37**	19.29	89
Combined average oil and NGL ($/boe)	**70.40**	42.69	65	**66.38**	36.84	80
Natural gas ($/mcf)	**3.44**	1.61	114	**3.14**	1.53	105
Revenue ($/boe)	**55.73**	29.02	92	**51.27**	25.97	97
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**70.55**	40.94	72	**64.85**	38.30	69
Edm Par Differential (US$/bbl)	**4.08**	3.51	16	**4.13**	5.76	(28)
WCS differential (US$/bbl)	**13.58**	9.06	50	**12.50**	13.67	(9)
Edmonton Par (Cdn$/bbl)	**83.76**	49.86	68	**75.91**	43.57	74
Hardisty Heavy (Cdn$/bbl)	**71.79**	42.44	69	**65.45**	32.98	98
NYMEX monthly settlement (US$/mmbtu)	**4.01**	1.97	103	**3.11**	1.88	65
AECO daily index (Cdn$/mcf)	**3.60**	2.23	61	**3.26**	2.08	57
AECO monthly index (Cdn$/mcf)	**2.47**	2.13	16	**2.75**	2.05	34

Third quarter 2021 vs. Third quarter 2020

Revenue per boe from oil, natural gas and NGL sales for Q3/21 increased by 92%, compared to the same period in 2020, due to improved and stabilized commodity prices realized in 2021 compared to the depressed prices realized in 2020 as a result of the COVID-19 pandemic.

The WTI benchmark price for Q3/21 averaged US$70.55/bbl, a 72% increase over the WTI benchmark for the same period in 2020 of US$40.94/bbl. Conversely, the WTI/Edmonton Par light oil differential widened to an average of US$4.08/bbl and the WTI/WCS heavy oil differential widened to an average of US$13.58/bbl. Apportionment on heavy volumes and fluctuating diluent costs continue to shape the heavy oil market in Alberta. Although all volumes were sold in the quarter, repricing on apportioned barrels and diluent costs can create fluctuations over time. In addition, Tamarack utilizes a netback maximization approach that may result in changes to both revenue and transportation expense over time. Combined, these factors contributed to a realized light oil wellhead price for the three months ended September 30, 2021 of $79.12/bbl versus $46.77/bbl in the same quarter of 2020 and a realized heavy oil wellhead price of $67.97/bbl in Q3/21 compared to $38.31/bbl in Q3/20.

In the third quarter, WTI pricing improved on average due to increased global demand mitigated by the partial unwinding of production cuts as part of the OPEC+ alliance output recovery scheme and production and refining disruptions in North America due to weather and fire related events. While the average price increased, volatility persisted during the quarter as COVID-19 variant strains across the globe created demand impacts and Asian markets reduced oil purchases through the quarter. While some near-term pricing risk still exists, pricing improvements, combined with increasing global demand and decreasing oil product inventories, are positive indicators of an improved pricing environment for the remainder of 2021 and 2022. 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 43% to $33.67/bbl in Q3/21 from $23.57/bbl in Q3/20. The increase is due largely to the improved WTI price year-over-year, which is the basis for condensate and butane pricing. In addition, decreased global oil and liquids inventories helped to establish favourable terms for the 2021-2022 contract season. In the third quarter, some of these gains were offset by the increased proportion of lower priced ethane volumes in the NGL portfolio as a result of the Anegada Acquisition. In addition, Alberta markets experienced microeconomic challenges due to disruption events at fractionation facilities in Alberta at the tail end of the quarter. These events, combined with restricted takeaway capacity out of the Grande Prairie area, will continue to impact realized prices through the early part of the fourth quarter.

Tamarack's realized natural gas price increased 114% to $3.44/mcf in Q3/21 from $1.61/mcf in Q3/20. The AECO daily benchmark price increased 61% to $3.60/mcf in Q3/21 from $2.23/mcf in Q3/20 while the NYMEX monthly settlement price increased 103% to US$4.01/mmbtu in Q3/21 from US$1.97/mmbtu in Q3/20. The increase in benchmark prices compared to the same quarter in the previous year was primarily due to increasing worldwide demand, decreasing inventories and lower supply as a result of decreased drilling activity in 2020. The increase 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.

First 9 months of 2021 vs. First 9 months of 2020

Revenue per boe from oil, natural gas and NGL sales for the nine months ended September 30, 2021 increased by 97%, compared to the same period in 2020, due to improved and stabilized commodity prices realized in 2021 compared to the depressed prices realized in 2020 as a result of the COVID-19 pandemic.

The WTI benchmark price for the nine months ended September 30, 2021 averaged US$64.85/bbl, a 69% increase over the WTI benchmark for the same period in 2020 of US$38.30/bbl. The WTI/Edmonton Par light oil differential narrowed to an average of US$4.13/bbl and the WTI/WCS heavy oil differential also narrowed to an average of US$12.50/bbl. Apportionment on heavy volumes and fluctuating diluent costs continue to shape the heavy oil market in Alberta. Tamarack utilizes a netback maximization approach that may result in changes to both revenue and transportation expense over time. Combined, these factors contributed to a realized light oil wellhead price for the nine months ended September 30, 2021 of $74.43/bbl versus $39.58/bbl in the same period of 2020 and a realized heavy oil wellhead price of $61.40/bbl for the nine months ended September 30, 2021 compared to $35.27/bbl in the same period of 2020.

For the nine months ended September 30, 2021, WTI pricing improved on average due to increased global demand mitigated by the partial unwinding of production cuts as part of the OPEC+ alliance output recovery scheme. While the average price increased, volatility persisted during the nine months as COVID-19 variant strains across the globe created demand impacts. While some near-term pricing risk still exists, pricing improvements, combined with increasing global demand and decreasing oil product inventories, are positive indicators of an improved pricing environment for the remainder of 2021 and 2022. 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 89% to $36.37/bbl in the nine months ended September 30, 2021 from $19.29/bbl in the same period of 2020. The increase is due largely to the improved WTI price year-over-year, which is the basis for condensate and butane pricing. In addition, decreased global oil and liquids inventories helped to establish favourable terms for the 2021-2022 contract season. Alberta markets experienced microeconomic challenges due to disruption events at fractionation facilities in Alberta at the tail end of the third quarter. These events, combined with restricted takeaway capacity out of the Grande Prairie area, will continue to impact realized prices through the early part of the fourth quarter.

Tamarack's realized natural gas price increased 105% to $3.14/mcf in the nine months ended September 30, 2021 from $1.53/mcf in the same period of 2020. The AECO daily benchmark price increased 57% to $3.26/mcf in the nine months ended September 30, 2021 from $2.08/mcf for the same period in 2020 while the NYMEX monthly settlement price increased 65% to US$3.11/mmbtu from US$1.88/mmbtu in the respective nine months then ended. The increase in benchmark prices compared to the same period in the previous year was 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 for the nine months ended September 30, 2021 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 September 30, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables:

		Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives						
WTI fixed price swap	***Volume (bbls/d)***	**3,000**	**–**	**–**	**–**	**–**
	Average Price (US$/bbl)	$48.63	–	–	–	–
WTI two-way collar	***Volume (bbls/d)***	**6,000**	**1,250**	**3,000**	**1,750**	**750**
	Average Bought Put (US$/bbl)	$38.33	$52.60	$52.58	$52.43	$53.00
	Average Sold Call (US$/bbl)	$59.33	$87.17	$88.26	$91.59	$88.88
	Average Premium (US$/bbl)	$0.50	$2.00	$2.01	$2.00	$2.00
WTI three-way collar	***Volume (bbls/d)***	**1,000**	**–**	**–**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	–	–	–	–
	Average Sold Call (US$/bbl)	$60.00	–	–	–	–
	Average Sold Put (US$/bbl)	$32.00	–	–	–	–
	Average Premium (US$/bbl)	$2.00	–	–	–	–
WTI three-way reverse collar	***Volume (bbls/d)***	**–**	**1,250**	**2,500**	**1,250**	**750**
	Average Bought Put (US$/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	$2.00
WTI Put	***Volume (bbls/d)***	**4,750**	**11,250**	**7,750**	**750**	**750**
	Average Bought Put (US$/bbl)	$51.59	$52.56	$52.71	$53.10	$53.10
	Average Premium (US$/bbl)	$2.18	$2.56	$2.70	$3.10	$3.10
Crude Oil Differential Derivatives						
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**9,750**	**6,000**	**6,000**	**–**	**–**
	Average Price (US$/bbl)	($5.07)	($3.88)	($3.88)	–	–
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**2,000**	**3,000**	**4,000**	**500**	**500**
	Average Price (US$/bbl)	($12.85)	($12.58)	($11.79)	($12.00)	($12.00)

		Summer 21	Winter 21-22	Summer 22
Natural Gas Derivatives				
AECO 5A	***Volume (GJ/d)***	**13,000**	**25,000**	**30,000**
	Average Price (CAD/GJ)	$2.58	$3.12	$2.44

		Q4 2021	Q1 2022	Q2 2022	Q3 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	***Amount ($US/month)***	**$6,000,000**	**$7,000,000**	**$6,500,000**	–
	Average Forward Rate (CAD/USD)	1.2297	1.2415	1.2440	–
CAD/USD collar style swap (with extension option)(1)	***Amount ($US/month)***	**$500,000**	–	–	–
	Floor Forward Rate (CAD/USD)	1.3000	–	–	–
	Ceiling Forward Rate (CAD/USD)	1.3615	–	–	–
CAD/USD put style swap	***Amount ($US/month)***	**$14,000,000**	–	–	–
	Floor Forward Rate (CAD/USD)	1.2186	–	–	–
	Average Premium (CAD/USD)	0.0099	–	–	–
CAD/USD target average rate forward(2)	***Amount ($US/month)***	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$166,667**
	Average Forward Rate (CAD/USD)	1.2400	1.2308	1.2288	1.2375
CAD/USD forward accumulator(3)	***Amount ($US/month)***	–	**$833,333**	–	–
	Average Forward Rate (CAD/USD)	–	1.2500	–	–

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

(2) Comprised of two $500,000 tranches with a maximum benefit to Tamarack over the term for each of 0.03 value points; once maximum value is reached, the instrument immediately terminates.

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

		2021	2022	2023	2024
Interest Rate Derivatives					
CDOR Interest Rate Fixed Price Swap	**Amount ($MM CAD/year)**	**$80.0**	**$80.0**	**$49.1**	**$6.4**
	Fixed Interest Rate	1.533%	1.533%	1.343%	1.043%

At September 30, 2021, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of $52.7 million (December 31, 2020 - $10.2 million net liability) recorded on the balance sheet. The Company recorded an unrealized loss of $2.2 million and a realized loss of $23.6 million in earnings for the three months ended September 30, 2021, compared to an unrealized loss of $9.0 million and a realized gain of $4.8 million during the same period in 2020. The Company recorded an unrealized loss of $33.0 million and a realized loss of $50.1 million in earnings for the nine months ended September 30, 2021, compared to an unrealized gain of $4.0 million and a realized gain of $31.9 million during the same period in 2020. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are credit grade banking institutions or large purchasers of commodities in the normal course of business. All counterparties have been assessed for credit worthiness.

Subsequent to September 30, 2021, the Company has entered into the following financial contracts:

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**–**	**1,250**	**7,500**	**2,750**
	Average Bought Put (US$/bbl)	–	$60.00	$60.00	$60.00
	Average Sold Call (US$/bbl)	–	$95.73	$93.95	$93.01
	Average Premium (US$/bbl)	–	$2.00	$2.00	$2.00
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**500**	**500**	**–**	**–**
	Average Price (US$/bbl)	($3.50)	($3.50)	–	–

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 September 30, 2021, the Company held the following physical commodity contracts:

		Summer 21	Winter 21-22
Natural Gas Physical			
AECO 5A	***Volume (GJ/d)***	**20,000**	**10,000**
	Average Price (CAD/GJ)	$2.43	$3.04
Malin	***Volume (DTH/d)***	**4,000**	**–**
	Average Price (US$/DTH)	$2.83	–

Subsequent to September 30, 2021, the Company has not entered into any physical commodity contracts.

Royalties

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
	2021	2020	% change	**2021**	2020	% change
Royalty expenses ($ thousands)	**$34,045**	$5,690	498	**$66,849**	$17,827	275
$/boe	**8.97**	2.87	213	**7.51**	2.95	155
Percent of sales (%)	**16**	10	60	**15**	11	36

Royalties as a percentage of revenue for both the third quarter of 2021 and the nine months ended September 30, 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 gross overriding royalties in conjunction with the Acquisitions. The Company expects royalty rates as a percentage of revenue to remain in the 17% to 18% range for the remainder of 2021 based on current forecast commodity pricing levels. On an absolute basis, royalty expense was higher in Q3/21 and the nine months ended September 30, 2021 compared to same period in 2020 due to an increase in commodity prices and production.

Net Production Expenses

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Production expenses	**$33,437**	$19,739	69	**$83,037**	$56,295	48
Less: processing income	**738**	299	147	**1,583**	542	192
Total net production expenses	**$32,699**	$19,440	68	**$81,454**	$55,753	46
Total ($/boe)	**$8.62**	$9.81	(12)	**$9.15**	$9.24	(1)

For the three and nine months ended September 30, 2021, per unit net production expenses (see "Non-IFRS Measures") were lower compared to the same periods in 2020. This resulted from the Clearwater acquisitions and the Anegada Acquisition properties having a lower per unit net production expense compared to the corporate average before the acquisitions, partially offset by the West Central Acquisition properties having higher per unit net production expenses compared to the corporate average before the acquisition. 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 September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Transportation expense - gas	**$2,799**	$1,101	154	**$5,798**	$3,414	70
Transportation expense - oil	**4,466**	543	722	**8,432**	2,412	250
Total transportation expense	**$7,265**	$1,644	342	**$14,230**	$5,826	144
Total ($/boe)	**$1.91**	$0.83	130	**$1.60**	$0.97	65

For the three and nine months ended September 30, 2021, per unit transportation expense was higher compared to the same periods in 2020. This increase was a result of the Clearwater assets acquired late in 2020 along with the 2021 Clearwater development program and Anegada Acquisition assets in 2021, requiring oil to be trucked to sales points driven by the strongest operating netback, which may result in higher transportation expenses but also additional revenue. Total transportation expenses were higher compared to the same periods in 2020 due to higher production and a larger proportion of volumes that require clean oil trucking.

Operating Netback

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2021**	2020	% change	**2021**	2020	% change
Average realized sales	**$55.73**	$29.02	92	**$51.27**	$25.97	97
Royalty expenses	**(8.97)**	(2.87)	213	**(7.51)**	(2.95)	155
Net production expenses	**(8.62)**	(9.81)	(12)	**(9.15)**	(9.24)	(1)
Transportation expense	**(1.91)**	(0.83)	130	**(1.60)**	(0.97)	65
Operating field netback	**36.23**	15.51	134	**33.01**	12.81	158
Realized commodity hedging gain (loss)	**(6.21)**	2.42	(357)	**(5.62)**	5.28	(206)
Operating netback	**$30.02**	$17.93	67	**$27.39**	$18.09	51

For the three and nine months ended September 30, 2021, operating netbacks per boe (see "Non-IFRS Measures") were higher than the same periods in 2020 primarily due to the higher commodity prices realized in 2021 and the increase in oil and NGL weighting, partially offset by higher transportation expense, higher royalties and the realized commodity hedging losses in 2021.

General and Administrative ("G&A") Expenses

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Gross costs	**$6,362**	$2,937	117	**$16,988**	$10,849	57
Capitalized costs and recoveries	**(1,362)**	(918)	48	**(3,968)**	(2,883)	38
General and administrative costs	**$5,000**	$2,019	148	**$13,020**	$7,966	63
Total ($/boe)	**$1.32**	$1.02	29	**$1.46**	$1.32	11

Gross and net G&A costs (all excluding transaction costs) for both the three and nine months ended September 30, 2021 were higher compared to the same periods in 2020, due to increased staffing levels related to the recently completed Acquisitions and the final determination of the annual incentive plan which is paid out in the first quarter of each year.

Net G&A costs on a per boe basis for the three and nine months ended September 30, 2021 were higher compared to the same period in 2020, due to increased staffing levels related to the recently completed Acquisitions and the Company receiving the Canada Emergency Wage Subsidy ("CEWS") in Q3/20, partially offset by higher overall production levels.

The Company incurred transaction costs related to the 2021 acquisitions, for the three and nine months ended September 30, 2021 in the amount of $1.1 million and $8.1 million, respectively, compared to no transaction costs in the same periods in 2020.

Stock-Based Compensation Expense

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Gross costs	**$1,664**	$1,729	(4)	**$6,748**	$4,801	41
Capitalized costs	**(506)**	(189)	168	**(2,957)**	(715)	314
Expensed stock-based compensation	**$1,158**	$1,540	(25)	**$3,791**	$4,086	(7)
Total ($/boe)	**$0.31**	$0.78	(60)	**$0.43**	$0.68	(37)

Stock-based compensation expense related to Stock Options, RSUs and PSUs for the three and nine months ended September 30, 2021 was lower compared to the same periods in 2020 due to increased capitalized costs as a result of increased capital activity in both Q3/21 and the nine months ended September 30, 2021, partially offset by grants being issued at a higher share price along with performance targets being exceeded resulting in additional PSUs being granted.

During the three months ended September 30, 2021, the Company issued 0.2 million Stock Options (at a weighted average exercise price of $2.39 per share), 0.3 million RSUs and 0.4 million PSUs compared to no Stock Options, 0.03 million RSUs and no PSUs during the same period in 2020.

During the nine months ended September 30, 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 September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Interest on bank debt	**$5,837**	$2,451	138	**$12,813**	$6,133	109
Fees associated with credit facility renewal	**424**	1	42,300	**1,085**	532	104
Interest on lease liabilities	**211**	206	2	**596**	644	(7)
Unrealized loss (gain) on foreign exchange	**(6,033)**	1,350	(547)	**1,426**	4,211	(66)
Unrealized loss (gain) on cross-currency swap	**6,039**	(1,359)	(544)	**(1,410)**	(4,266)	(67)
Accretion of decommissioning obligations	**1,330**	599	122	**3,474**	1,879	85
Total finance expense	**$7,808**	$3,248	140	**$17,984**	$9,133	97
Total ($/boe)	**$2.06**	$1.64	26	**$2.02**	$1.51	34
Average drawings on bank debt	**$512,132**	$205,757	149	**$364,015**	$205,067	78

Total finance expense for the three and nine months ended September 30, 2021 was higher than the same periods in 2020 as a result of higher average drawings on bank debt, fees associated with the redetermination of the credit facility with respect to the Acquisitions and increased borrowing rates related to the bank renewal in June 2020.

Depletion, Depreciation and Amortization (“DD&A”)

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2021**	2020	% change	**2021**	2020	% change
Depletion and depreciation	**$72,463**	$26,656	172	**$149,770**	$93,228	61
Amortization of undeveloped leases	**196**	157	25	**518**	440	18
Total	**$72,659**	$26,813	171	**$150,288**	$93,668	60
Depletion and depreciation ($/boe)	**$19.09**	$13.46	42	**$16.83**	$15.45	9
Amortization ($/boe)	**0.05**	0.08	(38)	**0.06**	0.07	(14)
Total ($/boe)	**$19.14**	$13.54	41	**$16.89**	$15.52	9

For the three and nine months ended September 30, 2021, DD&A expense per boe was higher relative to the same periods in 2020. The increase was due to recent acquisitions that have a higher DD&A expense per boe than the corporate average and the impairment recovery that was taken in Q2/21, partially offset by the completion of the Company’s December 31, 2020 reserve report which resulted in an increase in Tamarack’s overall proved and probable oil and natural gas reserve base following the 2020 drilling program and the West Central Acquisition; and an impairment charge taken in both Q1/20 and Q4/20 which reduced the net book value of assets to be depleted.

On an absolute basis, DD&A expense was higher for the three and nine months ended September 30, 2021 due to higher production.

Impairment (Impairment Reversal) of Property, Plant and Equipment

At September 30, 2021, there were no indicators of impairment or reversal of impairment identified.

At June 30, 2021, there were indicators of reversal of impairment identified in the Company's Cardium oil cash-generating unit ("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 and transportation 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 fair value less costs of disposal 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 oil and natural gas 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 asset.

Income Taxes

The Company did not incur any cash tax expense for the three and nine months ended September 30, 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 and nine months ended September 30, 2021, a deferred income tax expense of $5.7 million and $78.3 million, respectively, was recognized compared to a deferred income tax recovery of $1.3 million and $89.6 million for the same periods in 2020.

Adjusted Funds Flow and Net Income (Loss)

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per share)	**2021**	2020	% change	**2021**	2020	% change
Cash flow from operating activities	**$100,558**	$26,965	273	**$179,247**	$101,431	77
Abandonment expenditures	**1,046**	552	89	**2,892**	2,554	13
Transaction costs	**1,125**	–	–	**8,110**	–	–
Changes in non-cash working capital	**(243)**	3,320	(107)	**25,930**	(10,131)	(356)
Adjusted funds flow	**$102,486**	$30,837	232	**$216,179**	$93,854	130
Per share - basic	**$0.25**	$0.14	79	**$0.64**	$0.42	52
Per share - diluted	**$0.25**	$0.14	79	**$0.63**	$0.42	50
Net income (loss)	**$20,032**	$(5,776)	(447)	**$250,060**	$(293,164)	(185)
Per share - basic	**$ 0.05**	$(0.03)	(267)	**$ 0.74**	$(1.32)	(156)
Per share - diluted	**$ 0.05**	$(0.03)	(267)	**$ 0.73**	$(1.32)	(155)

Adjusted funds flow (see "Non-IFRS Measures") and cash flow from operating activities for the three and nine months ended September 30, 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 recent acquisitions, higher commodity prices and an increase in oil and NGL weighting, partially offset by realized hedging loss in 2021 and higher royalty expense.

The Company recorded net income of $20.0 million ($0.05 per share basic and diluted) and net income of $250.1 million ($0.74 per share basic and $0.73 per share diluted) during the three and nine months ended September, 30 2021 compared to a net loss of $5.8 million ($0.03 per share basic and diluted) and a net loss of $293.2 million ($1.32 per share basic and diluted), respectively in the same periods in 2020.

The increase in net income for the three months ended September 30, 2021 as compared to the same period in 2020 is primarily due to an increase in revenue and a decrease in unrealized hedging loss, partially offset by higher royalty costs, realized hedging losses, 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 all expenses are largely attributable to the increase in the Company's production resulting from the Acquisitions beginning in the third quarter of 2020.

The increase in net income for the nine months ended September 30, 2021 as compared to the same period in 2020 is primarily due to an increase in revenue and an impairment reversal taken in Q2/21, partially offset by higher royalty costs, higher combined realized and unrealized hedging losses, 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 all expenses are largely attributable to the increase in the Company's production resulting from the Acquisitions beginning in the third quarter of 2020.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

Year-over-Year	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2021**	2020	% change	**2021**	2020	% change
Land	**$4,158**	$166	2,405	**$6,585**	$3,345	97
Geological and geophysical	**68**	5	1,260	**403**	14	2,779
Drilling and completion	**48,316**	4,339	1,014	**106,480**	63,617	67
Equipment and facilities	**16,086**	4,988	222	**31,747**	20,856	52
Capitalized G&A	**1,197**	786	52	**3,370**	2,400	40
Office equipment	**153**	80	91	**902**	223	304
Total capital expenditures	**$69,978**	$10,364	575	**$149,487**	$90,455	65

During the third quarter of 2021, the Company drilled, completed and equipped, eight (8.0 net) Clearwater oil wells, seven (7.0 net) Charlie Lake oil wells and three (3.0 net) Viking oil wells. The Company commissioned its Nipisi Clearwater gas conservation project, which currently is conserving 2.0 mmcf/d of natural gas, along with additional infrastructure projects in the Clearwater area.

For the nine months ended September 30, 2021, the Company drilled, completed and equipped thirty-four (34.0 net) Viking oil wells, thirty-two (31.5 net) Clearwater oil wells, nine (9.0 net) Charlie Lake oil wells, six (6.0 net) water source and injector wells and two (0.8 net) Falher gas wells.

For the nine months ended September 30,2021 Drilling Summary		
	Gross	Net
Viking	34.0	34.0
Clearwater	32.0	31.5
Charlie Lake	9.0	9.0
Water source and injectors	6.0	6.0
Falher	2.0	0.8
	83.0	81.3

Acquisitions and Dispositions

On August 31, 2021 the Company completed the acquisition of certain oil and gas properties located in the Southern Clearwater area of Alberta. The acquisition was completed 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 were 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**

On June 1, 2021, Tamarack acquired all of the issued and outstanding common shares of Anegada Oil Corp. (the “Anegada Acquisition”). The assets acquired from Anegada included certain oil and natural gas properties located in the Grande Prairie area of Alberta. The acquisition was completed for total cash consideration of $258.2 million and the issuance of 105.3 million common shares of the Company. Based upon Tamarack’s share price of $2.66 per common share, the total consideration was approximately $538.4 million. 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 a newly formed Charlie Lake cash-generating unit (“CGU”). Assets held for sale primarily relate to the sale of a gross overriding royalty (“GORR”) on the Anegada Acquisition assets for gross proceeds of $32.0 million.

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

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	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**

The above amounts are estimates, which were made by management at the time of preparation of the condensed consolidated interim financial statements based on information then available.

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

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

The first acquisition included assets in both the Provost and Nipisi areas (the "Acquisition 1") was completed for total cash consideration of $102.6 million. There were $0.7 million of transaction costs 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 Viking oil cash-generating unit ("CGU") and the Clearwater oil CGU. Assets held for sale relate to the sale of a GORR on the Acquisition 1 Nipisi area 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 property, plant and equipment has been estimated with reference to an internally prepared reserves evaluation for the acquired properties. The estimated proved and probable oil and natural gas reserve and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 8%.

The second acquisition in the Nipisi area (the “Acquisition 2”) was completed for total cash consideration of $34.4 million including $0.9 million of capitalized transaction costs and the issuance of 4.9 million Common Shares of the Company. Based upon Tamarack’s share price on the date of closing of $2.09 per 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 were included in the Clearwater oil CGU. Assets held for sale relate to the sale of a GORR on the Acquisition 2 Nipisi area assets.

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

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

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 nine months ended September 30, 2021 the Company executed further tuck-in acquisitions in the Clearwater oil CGU and Charlie Lake oil CGU for approximately $8.3 million.

For the nine months ended September 30, 2021, the Company disposed of a 2% gross overriding royalty on a select portion of the Charlie Lake properties acquired from Anegada for net proceeds of $31.6 million. The Company also disposed of a 4% gross overriding royalty on a select portion of the Nipisi properties acquired from Acquisition 1 and Acquisition 2 for net proceeds of $13.5 million and recorded a gain on disposition of $7.5 million. The Company also disposed of non-core properties for proceeds of $1.1 million and recorded a gain on disposition of $0.3 million.

Share Capital

(thousands)	**September 30, 2021**	October 27, 2021	December 31, 2020
Common shares outstanding	**406,431**	406,339	262,776
Common shares held in treasury	**656**	748	747
Options outstanding	**2,624**	2,517	1,904
RSUs outstanding	**5,779**	5,515	5,365
PSUs outstanding	**5,656**	5,463	3,564

At September 30, 2021, Tamarack Acquisition Corp. had 740,307 preferred shares ("TAC Preferred Shares") issued and outstanding (December 31, 2020 – 740,307). The TAC Preferred Shares were fully vested and exchangeable into 711,834 Common Shares (December 31, 2020 – 711,834) of Tamarack at an exchange price of $3.12 per Common Share.

On March 25, 2021, the Company issued 30,303,000 Common Shares at $2.25 per common share for total gross proceeds of $68.2 million and the Company issued 4,888,889 Common Shares in connection with the Nipisi area acquisition in Q1 2021.

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

On June 1, 2021, the Company issued 105,341,880 Common Shares as partial consideration in connection with the Anegada Acquisition.

Liquidity and Capital Resources

($ thousands)	**September 30, 2021**	December 31, 2020
Working capital deficiency (surplus)	**$(1,253)**	$8,454
Bank debt	**520,961**	210,857
Net debt	**519,708**	219,311
Quarterly adjusted funds flow	**$102,486**	$28,894
Annualized factor	**4**	4
Annualized adjusted funds flow	**409,944**	115,576
Net debt to annualized adjusted funds flow	**1.3x**	1.9x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency (surplus) (see "Non-IFRS Measures"), totaled $519.7 million as at September 30, 2021. This compares to the Company's net debt of $199.6 million in Q3/20 and $219.3 million in Q4/20. Tamarack's Q3/21 net debt to annualized adjusted funds flow (see "Non-IFRS Measures") was 1.3 times as the Company carried out the Acquisitions in March 2021 and June 2021. The Company's forecasted plan is to reduce the ratio to 1.2x by the end of Q4/21.

The Company's $112.9 million investment in capital additions and acquisitions during Q3/21 was funded by Tamarack's adjusted funds flow (see "Non-IFRS Measures") of $102.5 million and an increase of net debt of $10.4 million.

Despite the improvement in commodity prices during the first nine months of 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.

At times, management believes the Company's prevailing share price does not adequately reflect the underlying value of Tamarack's assets. As such, we may utilize an NCIB program through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company has the option to purchase our Common Shares for cancellation, thereby reducing the total number of shares outstanding. The Company suspended the NCIB program during the second quarter of 2020, however Tamarack has applied to the TSX to reinstate the program commencing in Q4/21.

Bank Debt

Tamarack currently has available a revolving credit facility in the amount of $470 million, a term credit facility in the amount of $100 million and an operating facility of $30 million (collectively, the "Facility") with a syndicate of lenders. A total of $521.0 million was drawn as of September 30, 2021 (December 31, 2020 – $210.9 million). The term credit facility is amortizing and reduces from $100 million to $75 million in December 2021, $40 million in March 2022 and nil in May 2022. The Company will, therefore, be required to pay any outstanding balances in excess of the term facility commitment amount on those dates. The revolving credit 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 total interest rate on the Facility is determined through a pricing grid that categorizes based on both a total amount drawn and a net debt-to-cash-flow ratio as defined in the Facility. The interest rate will vary depending on: the lending vehicle employed; the total loan value drawn; and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and LIBOR (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 3.00% to a high of the banks' posted rates plus 5.50%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 2.00% to a high of the banks' prime rates plus 4.50%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.25% on the undrawn portion of the Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates. As at September 30, 2021, the Facility was secured by a $1.2 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by May 31, 2022.

The Facility is governed by a Consolidated Net Debt to Cash Flow Ratio (see "Non-IFRS Measures) financial covenant. Subject to quarterly testing, the Consolidated Net Debt to Cash Flow Ratio threshold decreases across the term of the facility from 3.50:1.00 at the first test on September 30, 2021, 3.00:1.00 on December 31, 2021 and 2.50:1.00 on March 31, 2022 and thereafter. The first quarterly test completed for September 30, 2021 was in compliance with this covenant and management's current 2021 and 2022 budgets forecast future compliance with this covenant.

Commitments

The following table summarizes the Company's commitments as at September 30, 2021:

($ thousands)	2021	2022	2023	2024	2025+
Bank debt[(1)]	$25,000	$75,000	$420,960	$ –	$ –
Lease[(2)]	56	229	229	229	172
Take or pay commitments[(3)]	933	4,023	3,894	–	–
Gas transportation[(4)]	642	2,539	947	272	11
Capital commitments[(5)]	–	52,261	70,172	–	–
Total	$26,631	$134,052	$496,202	$501	$183

(1) If not extended by May 31, 2022, the 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) Pipeline commitments to deliver a minimum of 636 m^3/d of crude oil/condensate and 455 m3/d of crude oil subject to a take-or-pay provision of \$9.00/m^3 and \$9.70/$m^{3,}$ respectively, escalating approximately 2% per annum. The terms started on January 1, 2019 and last for 60 months.

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

(5) 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 $122.4 million 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 condensed consolidated interim financial statements.

Unit Cost Calculation

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

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
DTH	dekatherm
GJ	gigajoule
IFRS	International Financial Reporting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
NGL	natural gas liquids
WCS	Western Canadian Select
WTI	West Texas Intermediate

Non–IFRS Measures

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

(a) **Adjusted Funds Flow -** Adjusted funds flow is calculated by taking cash-flow from operating activities and adding back changes in non-cash working capital, expenditures on decommissioning obligations and corporate 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 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 13 in the section titled “Adjusted Funds Flow and Net Income (Loss)”.

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

(c) **Net Debt and Working Capital Deficiency (Surplus) -** Tamarack closely monitors our capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of our capital structure. The Company uses net debt (bank debt plus working capital surplus or deficiency, including the fair value of cross-currency swaps and excluding the current portion of the fair value of financial instruments, bank debt, 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)	**September 30, 2021**	December 31, 2020
Accounts payable and accrued liabilities	**$97,361**	$38,903
Cross currency swap liability	**186**	1,597
Accounts receivable	**(94,699)**	(30,781)
Prepaid expenses and deposits	**(4,101)**	(1,265)
Working capital deficiency (surplus)	**(1,253)**	8,454
Bank debt	**520,961**	210,857
Net debt	**$519,708**	$219,311

(d) **Net Debt to Annualized Adjusted Funds Flow** – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of the Company and our ability to pay off debt and take on new debt, if necessary, using the most recent quarter's results. The calculation of the Company's netbacks can be seen starting on page 18 in the section titled "Liquidity and Capital Resources".

(e) **Year-end Net Debt to Trailing Annual Adjusted Funds Flow -** 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** (previously referred to as "free adjusted funds flow") **–** 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	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2021**	2020	% change	**2021**	2020	% change
Adjusted funds flow	**$102,486**	$30,837	232	**$216,179**	$93,854	130
Less: capital expenditures	**69,978**	10,364	575	**149,487**	90,455	65
Free funds flow	**$32,508**	$20,473	59	**$66,692**	$3,399	1,862

(g) **Consolidated Net Debt to Cash Flow Ratio** – Management is subject to certain terms as defined by the Amended and Restated Credit Agreement ("ARCA"). As defined by the ARCA, consolidated net debt to cash flow ratio is defined as the ratio at the end of the quarter of (i) net debt – the working capital adjustment plus consolidated debt (bank and other) – divided by (ii) cash flow – the net income for the defined period adjusted for any non-cash items, acquisitions and dispositions. For the first four quarters, the cash flow period will be the most recent quarter annualized. There after, cash flow will be represented by the prior twelve month's trailing cash flow.

Selected Quarterly Information

Three months ended	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2020	Sep. 30, 2020	Jun. 30, 2020	Mar. 31, 2020	Dec. 31, 2019
Sales volumes								
Natural gas *(mcf/d)*	**72,935**	60,887	52,466	53,738	53,420	49,610	52,912	54,462
Oil and NGL *(bbls/d)*	**29,100**	22,268	15,194	13,093	12,630	12,729	14,712	15,782
Average boe/d *(6:1)*	**41,256**	32,416	23,938	22,049	21,533	20,997	23,531	24,859
Product prices								
Natural gas *($/mcf)*	**3.44**	2.77	3.15	2.46	1.61	1.37	1.61	2.26
Oil and NGL *($/bbl)*	**70.40**	67.47	56.91	43.22	42.69	23.40	43.41	59.51
Oil equivalent *($/boe)*	**55.73**	51.55	43.03	31.67	29.02	17.42	30.76	42.72
(000s, except per share amounts)								
Financial results								
Gross revenues	**211,527**	152,061	92,696	64,238	57,491	33,295	65,872	97,699
Cash provided by operating activities	**100,558**	40,253	38,436	23,859	26,965	28,107	46,359	54,623
Adjusted funds flow [(2)]	**102,486**	71,741	41,236	28,894	30,837	20,972	42,045	54,742
Per share – basic	**0.25**	0.21	0.16	0.13	0.14	0.09	0.19	0.25
Per share – diluted	**0.25**	0.21	0.16	0.13	0.14	0.09	0.19	0.25
Net income (loss)	**20,032**	230,194	(166)	(18,220)	(5,776)	(36,067)	(251,321)	(50,546)
Per share – basic	**0.05**	0.69	(0.00)	(0.08)	(0.03)	(0.16)	(1.13)	(0.23)
Per share – diluted	**0.05**	0.67	(0.00)	(0.08)	(0.03)	(0.16)	(1.13)	(0.23)
Capital expenditures	**69,978**	30,805	48,704	13,088	10,364	6,218	73,873	22,954
Acquisitions[(1)]	**52,004**	539,506	147,187	94,684	4,127	–	–	250
Dispositions[(1)]	**(8,140)**	(32,283)	(13,884)	(15,525)	–	–	–	–
Total assets	**2,230,382**	2,180,303	1,199,743	1,027,600	963,220	935,892	984,045	1,247,119
Net debt[(2)]	**519,708**	505,992	286,175	219,311	199,561	213,066	227,151	189,481
Bank debt	**520,961**	520,012	270,810	210,857	198,994	206,467	209,423	192,907
Decommissioning obligations	**265,929**	264,791	242,692	245,437	241,047	198,485	186,816	184,846

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

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

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flows and earnings.
- The volatility in decommissioning obligations due to fluctuations in discount rates and acquisitions.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On June 1, 2021, Tamarack closed the Anegada Acquisition of Charlie Lake area properties in the Grande Prairie area 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 Provost and Nipisi areas of Alberta. The assets include approximately 2,800 boe/d of low decline (~16%) oil weighted assets under waterflood, along with adding approximately 38,400 net acres in the Clearwater oil play of Alberta for a total purchase price of approximately $147.2 million.

- On December 21, 2020, the Company completed two acquisitions of certain oil properties located in the Greater Nipisi area of Alberta. The assets include approximately 2,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.
- On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets include approximately 2,500 boe/d (52% oil and NGL) of production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.
- The Company recorded an impairment 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.
- The Company recorded an impairment charge in Q4/19 in the amount of $68.0 million on its Cardium oil CGU due to decreased current and forecasted natural gas prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit.

Critical Accounting Estimates

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

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

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

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

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

The Company assesses PP&E for impairment or impairment reversal whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment or impairment reversal exists, the Company performs an impairment test related to the specific CGU. The determination of the estimated recoverable amount of a CGU is based on estimates of proved and probable oil and natural gas reserves and the related cash flows. By their nature, these estimates of proved and probable oil and natural gas reserves and the related cash flows are subject to uncertainty including significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs and forecasted future development costs and the impact on the financial statements of future periods could be material.

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

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

(e) **Business combinations –** The application of the Company's accounting policy for business combinations requires management to make certain 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 petroleum and natural gas properties (included in property, plant and equipment) derived from estimated recoverable quantities of proved and probable oil and natural gas reserves and the related cash flows being acquired.

Disclosure Controls and Internal Controls over Financial Reporting

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

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

The Company established procedures for remote working and opened the corporate head office on a limited and intermittent basis during the period. Working from home required certain processes and controls that were previously done or documented manually to be completed and retained in electronic form. The changes required by the current environment resulted in no significant changes in the Company's internal controls during the period ended September 30, 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecasts. Most of these risks (financial, operational or regulatory) are not within the Company's control. While the following sections discuss some of these risks, they should not be construed as exhaustive. For additional information on the risks relating to Tamarack's business, see "Risk Factors" in Tamarack's Annual Information Form for the year ended December 31, 2020, which can be found on SEDAR at www.sedar.com.

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

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

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

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

The COVID-19 pandemic continues to rapidly evolve and the full impact on the Company's business, financial condition and results of operations, as well as the Company's future capital expenditures and other discretionary items, will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence, including: the geographic spread of the virus; the duration and extent of the pandemic, the spread of new variant strains of the virus, further actions that may be taken by governmental authorities, including in respect of 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, 2020.

(b) **Continued Volatility in Commodity and Petroleum Products Prices**

Inherent to the business of producing oil and gas, the Company's revenue and cash provided by operating activities is subject to commodity and petroleum product price risk. Commodity prices are impacted by world economic events that dictate levels of supply and demand, including the actions taken by OPEC and non-OPEC oil and gas exporting countries to set production levels and influence oil prices, and the currency exchange relationship between the Canadian and U.S. dollar. Further, more than a year after being declared a global pandemic by the World Health Organization in March 2020, COVID-19 continues to impact global economic conditions. Global financial markets, and commodity prices in particular, have experienced significant volatility and uncertainty. Crude oil and natural gas prices have recovered from the historic lows observed in the first two quarters of 2020 and exceeded pre-pandemic levels during the first half and into the third quarter 2021. While the current outlook for commodity prices is relatively strong, long-term price support from future demand remains uncertain. Tamarack continues to respond to market fundamentals and is carefully monitoring emerging developments. Tamarack is committed to maintaining its strong balance sheet and financial liquidity and is well positioned to withstand challenges and take advantage of the opportunities presented by the current business environment.

Financial Risks

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

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

Operational Risks

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

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

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

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

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. The Company's exploration and production activities emit greenhouse gasses ("GHG") which may require Tamarack to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on Tamarack's business, financial condition, results of operations and prospects. Restrictive new legislation is a risk the Company cannot control.

Forward-Looking Statements

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

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

- Tamarack’s business strategy, objectives, strength and focus, including with respect to acquisitions;
- the effects of the Anegada Acquisition, the Clearwater Acquisitions, the Nipisi Acquisitions, and the Southern Clearwater Acquisition and other Clearwater infrastructure initiatives on the Company’s strategy and profitability;
- the effects of the non-cash asset swap transaction completed during Q3 whereby the Company disposed of certain oil properties located in the Lochend and Harmattan areas of Alberta, and acquired certain oil properties in the Monarch area of Alberta on the Company’s strategy and profitability;
- the effects and profitability of the Charlie Lake oil play and related acquisitions;
- expectations regarding the Company’s five-year plan and consolidation of assets in the Clearwater;
- the intentions of management and the Company;
- the COVID-19 pandemic, the Company’s and governmental authorities’ current and planned responses thereto and the impact thereof on, without limitation, the Company in particular and the oil and gas industry in general;
- uncertainty regarding the full impact of COVID-19 on global economies, oil demand and commodity prices;
- uncertainty regarding the duration and extent of oil demand destruction resulting from the COVID-19 pandemic;
- the continued impact of disruption events at fractionation facilities in Alberta;
- the continued impact of lower priced ethane volumes in the Company’s NGL portfolio as a result of the Anegada acquisition;
- applications and grants under the Canada Emergency Wage Subsidy (“**CEWS**”), Alberta Site Rehabilitation Program (“**SRP**”) and Saskatchewan Accelerated Site Closure Program (“**ASCP**”) programs;
- the Company’s commitment to the practices outlined in the Environmental, Social and Governance Sustainability Report published in Q3 2020;
- the Company’s intention to release an updated Sustainability Report in the fourth quarter of 2021;
- the Company’s intention to reinstate the NCIB program in the future;
- expectations relating to future realized commodity prices, volatile commodity prices and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing;

- Tamarack's financial and physical hedging program;
- expectations regarding the Company's forecasted year end 2021 net debt to Q4/21 annualized adjusted funds flow;
- Tamarack's commitment to maintaining financial flexibility;
- Tamarack being well positioned from a liquidity standpoint;
- committed capital spending to develop the GORR lands and timing thereof;
- Tamarack's exposure to diversified gas markets and the effects thereof;
- expectation relating to risk mitigation and realized price improvements from exposure to diversified gas markets;
- Tamarack's third-party gas sales contracts that provide diversification of the Company's natural gas price exposure and mitigate individual market volatility risk;
- Tamarack's use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack's use of commodity, foreign exchange and interest rate contracts and risk management thereof;
- expectations as to royalty rates as a percentage of revenue;
- expectations relating to the timing for paying cash tax;
- Tamarack's strategy for preserving balance sheet strength;
- deferred tax assets, including in respect of deferred income tax;
- future RSU and PSU settlements;
- Tamarack's future intentions with respect to return of capital including dividends and share buybacks;
- expectations regarding net debt reduction and debt targets;
- Tamarack's intention to return free funds flow to shareholders;
- the timing and implementation of the Company's dividend policy;
- the granting of any special dividends or the implementation of any share buyback program or other supplements to the base dividend;
- statements regarding plans or expectations for the declaration of future dividends and the amount thereof;
- the availability, size, terms, use and renewal of the Company's facility;
- management's expectations regarding the Company's ability to conform to its financial covenants;
- contractual obligations and commitments; and
- estimates used to calculate decommissioning obligations and depletion of PP&E.

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

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production expenses and transportation expense;
- estimated proved and probable oil and natural gas reserves;
- the 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 release an updated Sustainability Report in the fourth quarter of 2021; and
- Tamarack's ability to execute its plans in response to the COVID-19 pandemic.

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

- the material uncertainties and risks described under the headings "Unit Cost Calculation", "Non-IFRS Measures", "Critical Accounting Estimates", "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", "Inaugural Dividend and Return of Capital Framework", "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;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production and transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources;
- the risk that Tamarack is unable to implement the dividend policy, or that dividend payments thereunder are reduced, suspended or cancelled;
- changes in tax, royalty and environmental legislation and any government policy;
- claims and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of applicable impact and environmental assessment review processes; and
- any legal proceedings, the results thereof and the impact on the Company's business, financial condition and results of operations.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also, to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, free funds flow financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tamarack to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2020, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, production, free funds flow, net debt, net debt to annualized adjusted funds flow, corporate decline rates, royalty rates and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non-IFRS Measures".

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

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited) (thousands)

	September 30, 2021	December 31, 2020
Assets		
Current assets:		
Accounts receivable	**$94,699**	$30,781
Prepaid expenses and deposits	**4,101**	1,265
Fair value of financial instruments (note 4)	**–**	981
	98,800	33,027
Property, plant and equipment (note 6 and 7)	**2,130,132**	943,430
Exploration and evaluation assets (note 8)	**1,450**	1,460
Deferred tax asset	**–**	49,683
	$2,230,382	$1,027,600
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$97,361**	$38,903
Bank debt (note 14)	**100,000**	–
Lease liabilities (note 10)	**3,681**	2,484
Decommissioning obligations (note 9)	**7,963**	6,000
Cross-currency swap (note 14)	**186**	1,597
Fair value of financial instruments (note 4)	**52,213**	9,942
	261,404	58,926
Bank debt (note 14)	**420,961**	210,857
Lease liabilities (note 10)	**8,193**	7,670
Fair value of financial instruments (note 4)	**529**	1,192
Decommissioning obligations (note 9)	**257,966**	239,437
Deferred tax liability	**157,426**	–
	1,106,479	518,082
Shareholders' equity:		
Share capital (note 12)	**1,238,642**	876,124
Treasury shares (note 12)	**(1,582)**	(703)
Contributed surplus	**54,033**	51,347
Deficit	**(167,190)**	(417,250)
	1,123,903	509,518
Subsequent events (note 4)		
Commitments (note 16)		
Contingency (note 17)		
	$2,230,382	$1,027,600

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
For the three and nine months ended September 30, 2021 and 2020
(unaudited) (thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2021	2020	**2021**	2020
Revenue:				
Oil and natural gas (note 5)	**$211,527**	$57,491	**$456,284**	$156,658
Processing income (note 5)	**738**	299	**1,583**	542
Royalties	**(34,045)**	(5,690)	**(66,849)**	(17,827)
Net revenue	**178,220**	52,100	**391,018**	139,373
Financial instrument contracts:				
Realized gain (loss) on financial instruments (note 4)	**(23,560)**	4,797	**(50,058)**	31,877
Unrealized gain (loss) on financial instruments (note 4)	**(2,153)**	(8,983)	**(32,979)**	3,965
Net revenue and gains (losses) on financial instruments	**152,507**	47,914	**307,981**	175,215
Expenses:				
Production	**33,437**	19,739	**83,037**	56,295
Transportation	**7,265**	1,644	**14,230**	5,826
General and administration	**5,000**	2,019	**13,020**	7,966
Transaction costs (note 7)	**1,125**	–	**8,110**	–
Stock-based compensation (note 15)	**1,158**	1,540	**3,791**	4,086
Finance	**7,808**	3,248	**17,984**	9,133
Depletion, depreciation and amortization (note 6 and 8)	**72,659**	26,813	**150,288**	93,668
Gain on disposition of property, plant and equipment (note 7)	**(892)**	–	**(8,735)**	–
Site rehabilitation program grant (note 9)	**(743)**	–	**(2,144)**	–
Impairment (reversal) of property, plant and equipment (note 6)	**–**	–	**(300,000)**	381,000
	126,817	55,003	**(20,419)**	557,974
Income (loss) before taxes	**25,690**	(7,089)	**328,400**	(382,759)
Deferred income tax recovery (expense)	**(5,658)**	1,313	**(78,340)**	89,595
Net income (loss) and comprehensive income (loss)	**$20,032**	$(5,776)	**$250,060**	$(293,164)
Net income (loss) per share (note 13):				
Basic	**$ 0.05**	$(0.03)	**$ 0.74**	$(1.32)
Diluted	**$ 0.05**	$(0.03)	**$ 0.73**	$(1.32)

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

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

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at December 31, 2019	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Purchase of common shares for cancellation	(664)	(2,551)	–	1,262	–	(1,289)
Purchase of common shares for RSU exercise	(3,641)	–	(3,857)	–	–	(3,857)
RSU exercise	2,433	–	3,250	(3,250)	–	–
Stock-based compensation	–	–	–	4,801	–	4,801
Net loss	–	–	–	–	(293,164)	(293,164)
Balance at September 30, 2020	220,921	$830,248	$(1,576)	$50,624	$(399,030)	$480,266
Balance at December 31, 2020	262,776	$876,124	$(703)	$51,347	$(417,250)	$509,518
Issue of common shares	143,565	365,427	–	–	–	365,427
Purchase of common shares for RSU and PSU exercise	(2,075)	–	(4,941)	–	–	(4,941)
RSU and PSU exercise	2,165	–	4,062	(4,062)	–	–
Share issue costs, net of tax of $869	–	(2,909)	–	–	–	(2,909)
Stock-based compensation	–	–	–	6,748	–	6,748
Net income	–	–	–	–	250,060	250,060
Balance at September 30, 2021	406,431	$1,238,642	$(1,582)	$54,033	$(167,190)	$1,123,903

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2021 and 2020
(unaudited) (thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2021	2020	**2021**	2020
Cash provided by (used in):				
Operating:				
Net income (loss)	**$20,032**	$(5,776)	**$250,060**	$(293,164)
Depletion, depreciation and amortization (note 6 and 8)	**72,659**	26,813	**150,288**	93,668
Stock-based compensation (note 15)	**1,158**	1,540	**3,791**	4,086
Gain on disposition of property, plant and equipment (note 7)	**(892)**	–	**(8,735)**	–
Site rehabilitation program grant (note 9)	**(743)**	–	**(2,144)**	–
Accretion expense on decommissioning obligations (note 9)	**1,330**	599	**3,474**	1,879
Unrealized loss (gain) on financial instruments (note 4)	**2,153**	8,983	**32,979**	(3,965)
Unrealized loss (gain) on foreign exchange	**(6,033)**	1,350	**1,426**	4,211
Unrealized loss (gain) on cross-currency swap (note 14)	**6,039**	(1,359)	**(1,410)**	(4,266)
Impairment (reversal) of property, plant and equipment (note 6)	**–**	–	**(300,000)**	381,000
Deferred income tax expense (recovery)	**5,658**	(1,313)	**78,340**	(89,595)
Abandonment expenditures (note 9)	**(1,046)**	(552)	**(2,892)**	(2,554)
Changes in non-cash working capital (note 11)	**243**	(3,320)	**(25,930)**	10,131
Cash provided by operating activities	**100,558**	26,965	**179,247**	101,431
Financing:				
Change in bank debt (note 14)	**6,982**	(8,823)	**308,678**	1,876
Repayment of acquired debt (note 7)	**–**	–	**(37,734)**	–
Net proceeds from issuance of shares (note 12)	**–**	–	**71,227**	–
Purchase of common shares for cancellation	**–**	–	**–**	(1,289)
Purchase of common shares for RSU and PSU exercises	**(228)**	(1,675)	**(4,941)**	(3,857)
Repayment of lease liabilities (note 10)	**(903)**	(623)	**(2,254)**	(1,707)
Changes in non-cash working capital (note 11)	**–**	–	**(1,005)**	–
Cash provided by (used in) financing activities	**5,851**	(11,121)	**333,971**	(4,977)
Investing:				
Property, plant and equipment additions (note 6)	**(69,736)**	(10,359)	**(148,773)**	(89,976)
Exploration and evaluation additions (note 8)	**(242)**	(5)	**(714)**	(479)
Acquisitions (note 7)	**(42,917)**	(4,127)	**(439,183)**	(4,127)
Proceeds from disposal of property, plant and equipment (note 7)	**–**	–	**46,167**	–
Changes in non-cash working capital (note 11)	**6,486**	(1,353)	**29,285**	(1,872)
Cash used in investing activities	**(106,409)**	(15,844)	**(513,218)**	(96,454)
Change in cash and cash equivalents	**–**	–	**–**	–
Cash and cash equivalents, beginning of period	**–**	–	**–**	–
Cash and cash equivalents, end of period	**$ –**	$ –	**$ –**	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The condensed consolidated interim financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 3300, 308 – 4th Avenue S.W., Calgary, Alberta, T2P 0H7.

2. Basis of preparation:

(a) Statement of compliance:

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

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2020. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2020. Certain prior period balances were reclassified to conform to current period presentation.

The consolidated financial statements were authorized for issue by the Board of Directors on October 27, 2021.

(b) Estimates and judgments:

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

3. COVID-19:

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 and vaccine rollout, changes in social and travel restrictions and businesses resuming regular operations. The crude oil market, as evidenced by the increases in benchmark crude oil pricing, has responded positively to the OPEC+ alliance largely maintaining production restrictions in conjunction with the global economic recovery, but the potential for volatility in crude oil demand and supply remains. 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 for the remainder of 2021 and beyond.

The Company has improved its flexibility and responsiveness by establishing capabilities and procedures for remote working and opening our corporate head office on a limited and intermittent basis during the nine months ended September 30, 2021. Tamarack remains committed to ensuring the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate, going above and beyond both Provincial and Federal government protocols.

4. Risk management contracts:

It is the Company's policy to economically hedge some oil and natural gas sales, foreign exchange rates and interest rates using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near-term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet its expected sales requirements. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are credit grade banking institutions or large purchasers of commodities in the normal course of business. All counterparties have been assessed for credit worthiness.

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

At September 30, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

		Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives						
WTI fixed price swap	***Volume (bbls/d)***	**3,000**	**–**	**–**	**–**	**–**
	Average Price (US$/bbl)	$48.63	–	–	–	–
WTI two-way collar	***Volume (bbls/d)***	**6,000**	**1,250**	**3,000**	**1,750**	**750**
	Average Bought Put (US$/bbl)	$38.33	$52.60	$52.58	$52.43	$53.00
	Average Sold Call (US$/bbl)	$59.33	$87.17	$88.26	$91.59	$88.88
	Average Premium (US$/bbl)	$0.50	$2.00	$2.01	$2.00	$2.00
WTI three-way collar	***Volume (bbls/d)***	**1,000**	**–**	**–**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	–	–	–	–
	Average Sold Call (US$/bbl)	$60.00	–	–	–	–
	Average Sold Put (US$/bbl)	$32.00	–	–	–	–
	Average Premium (US$/bbl)	$2.00	–	–	–	–
WTI three-way reverse collar	***Volume (bbls/d)***	**–**	**1,250**	**2,500**	**1,250**	**750**
	Average Bought Put (US$/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	$2.00
WTI Put	***Volume (bbls/d)***	**4,750**	**11,250**	**7,750**	**750**	**750**
	Average Bought Put (US$/bbl)	$51.59	$52.56	$52.71	$53.10	$53.10
	Average Premium (US$/bbl)	$2.18	$2.56	$2.70	$3.10	$3.10
Crude Oil Differential Derivatives						
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**9,750**	**6,000**	**6,000**	**–**	**–**
	Average Price (US$/bbl)	($5.07)	($3.88)	($3.88)	–	–
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**2,000**	**3,000**	**4,000**	**500**	**500**
	Average Price (US$/bbl)	($12.85)	($12.58)	($11.79)	($12.00)	($12.00)

		Summer 21	Winter 21-22	Summer 22
Natural Gas Derivatives				
AECO 5A	***Volume (GJ/d)***	**13,000**	**25,000**	**30,000**
	Average Price (CAD/GJ)	$2.58	$3.12	$2.44

		Q4 2021	Q1 2022	Q2 2022	Q3 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	***Amount ($US/month)***	**$6,000,000**	**$7,000,000**	**$6,500,000**	–
	Average Forward Rate (CAD/USD)	1.2297	1.2415	1.2440	–
CAD/USD collar style swap (with extension option)(1)	***Amount ($US/month)***	**$500,000**	–	–	–
	Floor Forward Rate (CAD/USD)	1.3000	–	–	–
	Ceiling Forward Rate (CAD/USD)	1.3615	–	–	–
CAD/USD put style swap	***Amount ($US/month)***	**$14,000,000**	–	–	–
	Floor Forward Rate (CAD/USD)	1.2186	–	–	–
	Average Premium (CAD/USD)	0.0099	–	–	–
CAD/USD target average rate forward(2)	***Amount ($US/month)***	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$166,667**
	Average Forward Rate (CAD/USD)	1.2400	1.2308	1.2288	1.2375
CAD/USD forward accumulator(3)	***Amount ($US/month)***	–	**$833,333**	–	–
	Average Forward Rate (CAD/USD)	–	1.2500	–	–

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

(2) Comprised of two $500,000 tranches with a maximum benefit to Tamarack over the term for each of 0.03 value points; once maximum value is reached, the instrument immediately terminates.

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

		2021	2022	2023	2024
Interest Rate Derivatives					
CDOR Interest Rate Fixed Price Swap	**Amount ($MM CAD/year)**	**$80.0**	**$80.0**	**$49.1**	**$6.4**
	Fixed Interest Rate	1.533%	1.533%	1.343%	1.043%

At September 30, 2021, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability of $52,742 (December 31, 2020 - $10,153 net liability) recorded on the balance sheet. The Company recorded an unrealized loss of $2,153 and a realized loss of $23,560 in earnings for the three months ended September 30, 2021 (September 30, 2020 - $8,983 unrealized loss and $4,797 realized gain). The Company recorded an unrealized loss of $32,979 and a realized loss of $50,058 in earnings for the nine months ended September 30, 2021 (September 30, 2020 - $3,965 unrealized gain and $31,877 realized gain).

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

At September 30, 2021, the Company held the following physical commodity contracts:

		Summer 21	Winter 21-22
Natural Gas Physical			
AECO 5A	***Volume (GJ/d)***	**20,000**	**10,000**
	Average Price (CAD/GJ)	$2.43	$3.04
Malin	***Volume (DTH/d)***	**4,000**	**–**
	Average Price (US$/DTH)	$2.83	**–**

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

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

Gross Amounts ($ thousands)	September 30, 2021	December 31, 2020
Risk management contracts		
Current asset	**$ –**	$981
Current liability	**(52,213)**	(9,942)
Long-term liability	**(529)**	(1,192)
Balance, end of the period	**$(52,742)**	$(10,153)

Subsequent to September 30, 2021, the Company has entered into the following derivative contracts:

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**–**	**1,250**	**7,500**	**2,750**
	Average Bought Put (US$/bbl)	–	$60.00	$60.00	$60.00
	Average Sold Call (US$/bbl)	–	$95.73	$93.95	$93.01
	Average Premium (US$/bbl)	–	$2.00	$2.00	$2.00
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**500**	**500**	**–**	**–**
	Average Price (US$/bbl)	($3.50)	($3.50)	–	–

Subsequent to September 30, 2021, the Company has not entered into any physical contracts.

5. Revenue:

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

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

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; the Clearwater oil play in the Nipisi area of northern Alberta; the Charlie Lake oil play in the Grande Prairie area of north western Alberta and the Barons Sand oil play in the Penny area of southern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by selling volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at September 30, 2021, five customers accounted for $60.7 million of the accounts receivable (December 31, 2020 - four customers accounted for $17.6 million).

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2021**	2020	**2021**	2020
Light oil	**$141,288**	$44,352	**$299,164**	$123,894
Heavy oil	**34,005**	560	**71,651**	1,593
Natural gas	**23,050**	7,890	**53,271**	21,838
Natural gas liquids	**13,184**	4,689	**32,198**	9,333
Oil and natural gas revenue	**$211,527**	$57,491	**$456,284**	$156,658
Processing income	**738**	299	**1,583**	542
Total revenue	**$212,265**	$57,790	**$457,867**	$157,200

Refer to note 4 for a listing of physical delivery contracts as at September 30, 2021.

Included in accounts receivable at September 30, 2021 was $76.1 million (December 31, 2020 - $24.2 million) of accrued production revenue. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at September 30, 2021, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

6. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at December 31, 2019	$2,076,327	$1,995	$2,078,322
Right-of-use assets	–	332	332
Property acquisitions	111,339	–	111,339
Cash additions	102,691	284	102,975
Decommissioning costs	45,850	–	45,850
Stock-based compensation	897	–	897
Transfer from exploration and evaluation assets (note 8)	148	–	148
Balance at December 31, 2020	2,337,252	2,611	2,339,863
Right-of-use assets (note 10)	–	2,350	2,350
Acquisitions (note 7)	883,187	73	883,260
Cash additions	147,871	902	148,773
Decommissioning costs	7,152	–	7,152
Stock-based compensation	2,957	–	2,957
Transfer from exploration and evaluation assets (note 8)	206	–	206
Disposals (note 7)	(65,662)	–	(65,662)
Balance at September 30, 2021	$3,312,963	$5,936	$3,318,899
Accumulated depletion, depreciation and impairment losses:			
Balance at December 31, 2019	$876,189	$1,183	$877,372
Depletion and depreciation	119,667	394	120,061
Impairment	399,000	–	399,000
Balance at December 31, 2020	1,394,856	1,577	1,396,433
Depletion and depreciation	149,403	367	149,770
Disposals (note 7)	(57,436)	–	(57,436)
Impairment reversal	(300,000)	–	(300,000)
Balance at September 30, 2021	$1,186,823	$1,944	$1,188,767

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2020	$942,396	$1,034	$943,430
At September 30, 2021	$2,126,140	$3,992	$2,130,132

The calculation of depletion at September 30, 2021 includes estimated future development costs of $921,732 (December 31, 2020 – $637,332) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of $87,283 (December 31, 2020 – $79,357).

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

($ thousands)	Processing facilities	Surface leases	Office leases	Total
Balance at December 31, 2019	$9,402	$1,736	$ –	$11,138
Lease additions	–	–	332	332
Depletion and depreciation	(1,366)	(150)	(145)	(1,661)
Impairment	(3,123)	(308)	–	(3,431)
Balance at December 31, 2020	$4,913	$1,278	$187	$6,378
Lease additions	–	–	2,350	2,350
Leases acquired (note 7)	1,551	–	73	1,624
Depletion and depreciation	(1,057)	(108)	(334)	(1,499)
Impairment reversal	1,746	–	–	1,746
Balance at September 30, 2021	$7,153	$1,170	$2,276	$10,599

At September 30, 2021 there were no indicators of impairment or reversal of impairment identified.

At June 30, 2021, there were indicators of reversal of impairment identified in the Company's Cardium oil cash-generating unit ("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 $300,000 was recorded as follows: the Cardium oil CGU reversed $140,000 of historical impairment charges and the Viking oil CGU reversed $160,000 of historical impairment charges. The estimated recoverable amount of these CGUs as at June 30, 2021, net of decommissioning obligations, was $257,200 for the Cardium oil CGU and $643,800 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 and transportation 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 fair value less costs of disposal 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 oil and natural gas commodity prices. The impairment reversal of $300,000 was allocated to property, plant and equipment in the amount of $298,254 and $1,746 was allocated to the right-of-use assets.

The following forecasted oil and natural gas commodity price assumptions were used in determining whether an impairment or reversal of impairment to the carrying value of the CGUs existed at June 30, 2021, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2021	2022	2023	2024	2025	2026	2027	2028	Thereafter
Exchange rate (US$/Cdn$)	0.8033	0.8017	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
WTI (US$/bbl)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	+2.0%/yr
Edmonton Par (Cdn$/bbl)	83.20	78.27	74.06	73.05	74.51	76.00	77.52	79.07	+2.0%/yr
AECO (Cdn$/MMbtu)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	+2.0%/yr

At March 31, 2020 impairment of $381,000 was recorded as a result of a decrease in current and forecast oil, natural gas and natural gas liquid prices. The impairment recognized relates to all of the Company's CGUs: the Viking oil CGU was impaired $235,000, the Cardium oil CGU was impaired $137,000, the Penny oil CGU was impaired $7,000 and the minor gas CGU was impaired $2,000. The estimated recoverable amount of these CGU's as at March 31, 2020, net of decommissioning obligations, was $447,900 for the Viking oil CGU, $137,900 for the Cardium oil CGU, $81,400 for the Penny oil CGU and ($11,100) for the minor gas 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, 2019 and updated by the Company's internal reserves evaluator to March 31, 2020 for production, production and transportation 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 amounts of all of the CGUs was determined using the fair value less costs of disposal methodology based on what Tamarack estimates it could receive for these assets if it disposed of them in the current environment taking into account lower oil, natural gas and NGL prices. The impairment of $381,000 was allocated to property, plant and equipment in the amount of $377,569 and $3,431 was allocated to the right-of-use assets.

7. Acquisitions and dispositions:

On August 31, 2021, the Company completed the acquisition of certain oil properties located in the Southern Clearwater area of Alberta. The acquisition was completed 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**

On June 1, 2021, Tamarack acquired all of the issued and outstanding common shares of Anegada Oil Corp. (the “Anegada Acquisition”). The assets acquired from Anegada included certain oil and natural gas properties located in the Grande Prairie area of Alberta. The acquisition was completed for total cash consideration of $258.2 million and the issuance of 105.3 million common shares of the Company. Based upon Tamarack’s share price of $2.66 per common share, the total consideration was approximately $538.4 million. 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 a newly formed Charlie Lake cash-generating unit (“CGU”). Assets held for sale primarily relate to the sale of a gross overriding royalty (“GORR”) on the Anegada Acquisition assets for gross proceeds of $32.0 million.

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

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	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**

The above amounts are estimates, which were made by management at the time of preparation of these condensed consolidated interim financial statements based on information then available.

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

Oil and natural gas revenue of $91.4 million and a net income of $23.5 million are included in the condensed consolidated interim statements of income (loss) and comprehensive income (loss) for the Anegada Acquisition assets since the closing date of June 1, 2021.

If the Anegada Acquisition had occurred on January 1, 2021, the incremental oil and natural gas revenue and net income recognized for the period ended September 30, 2021 and the pro forma results would have been as follows:

Period ended September 30, 2021 ($ thousands)	**As stated**	**Anegada Acquisition**	*(unaudited)* **Pro Forma**
Oil and natural gas revenue	$456,284	$83,269	$539,553
Net income	$250,060	$9,875	$259,935

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

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

The first acquisition included assets in both the Provost and Nipisi areas (the "Acquisition 1") was completed for total cash consideration of $102.6 million. There were $0.7 million of transaction costs 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 Viking oil cash-generating unit ("CGU") and the Clearwater oil CGU. Assets held for sale relate to the sale of a GORR on the Acquisition 1 Nipisi area 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 property, plant and equipment has been estimated with reference to an internally prepared reserves evaluation for the acquired properties. The estimated proved and probable oil and natural gas reserves and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 8%.

Oil and natural gas revenue of $36.2 million and a net income of $7.5 million are included in the condensed consolidated interim statements of income (loss) and comprehensive income (loss) for the Acquisition 1 assets since the closing date of March 25, 2021.

If the acquisition had occurred on January 1, 2021, the incremental oil and natural gas revenue and income recognized for the period ended September 30, 2021 and the pro forma results would have been as follows:

Period ended September 30, 2021 ($ thousands)	**As stated**	**Acquisition 1**	*(unaudited)* **Pro Forma**
Oil and natural gas revenue	$456,284	$11,305	$467,589
Net income	$250,060	2,314	$252,374

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

The second acquisition in the Nipisi area (the "Acquisition 2") was completed for total cash consideration of $34.4 million including $0.9 million of capitalized transaction costs and the issuance of 4.9 million common shares of the Company. Based upon Tamarack's share price on the date of closing of $2.09 per 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 Acquisition 2 Nipisi area assets.

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

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

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 nine months ended September 30, 2021, the Company executed further tuck-in acquisitions in the Clearwater oil CGU and Charlie Lake oil CGU for approximately $8.3 million.

For the nine months ended September 30, 2021, the Company disposed of a 2% gross overriding royalty on a select portion of the Charlie Lake properties acquired from Anegada for net proceeds of $31.6 million. The Company also disposed of a 4% gross overriding royalty on a select portion of the Nipisi properties acquired from Acquisition 1 and Acquisition 2 for net proceeds of $13.5 million and recorded a gain on disposition of $7.5 million. The Company also disposed of non-core properties for proceeds of $1.1 million and recorded a gain on disposition of $0.3 million.

8. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at December 31, 2019	$25,854
Additions	568
Transfer to property, plant and equipment (note 6)	(148)
Balance at December 31, 2020	26,274
Additions	714
Disposal (note 7)	(3,169)
Transfer to property, plant and equipment (note 6)	(206)
Balance at September 30, 2021	$23,613
Accumulated amortization and impairment:	
Balance at December 31, 2019	$24,217
Amortization	597
Balance at December 31, 2020	24,814
Amortization	518
Disposal (note 7)	(3,169)
Balance at September 30, 2021	$22,163

	Total
Carrying amounts:	
At December 31, 2020	$1,460
At September 30, 2021	$1,450

9. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $270.1 million at September 30, 2021 (December 31, 2020 – $233.9 million), which is expected to be incurred between 2021 and 2045. A risk-free rate of 2.0% (December 31, 2020 – 1.2%) and an inflation rate of 1.7% (December 31, 2020 – 1.5%) is used to calculate the present value of the decommissioning obligations at September 30, 2021 as presented in the table below:

($ thousands)	Nine months ended September 30, 2021	Year Ended December 31, 2020
Balance, beginning of the period	**$245,437**	$184,846
Liabilities incurred	**6,614**	3,839
Liabilities acquired (note 7)	**16,182**	17,388
Change in estimates	**(17,767)**	20,051
Change in discount rate on acquisition	**18,305**	21,960
Expenditures	**(2,892)**	(3,825)
Site rehabilitation program grant	**(2,144)**	(1,395)
Liabilities disposed	**(1,280)**	–
Accretion	**3,474**	2,573
Balance, end of the period	**$265,929**	$245,437

Revisions due to the change of discount rate on acquisitions of $18.3 million results from the difference between the fair value discount rate on the acquisition date and the subsequent revaluation using the risk-free rate.

The change in estimate for the nine months ended September 30, 2021 resulted from decommissioning obligations being revalued using a risk-free rate of 2.0% and an inflation rate of 1.7% as opposed to a risk-free rate of 1.2% and an inflation rate of 1.5% used at December 31, 2020.

During the three and nine months ended September 30, 2021, approximately $0.7 million and $2.1 million (December 31, 2020 – $1.4 million) was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work.

Timing of decommissioning obligation expenditures expected to be incurred are:

($ thousands)	As at September 30, 2021
Decommissioning obligations – Less than 1 year	$7,963
Decommissioning obligations – Greater than 1 year	257,966
Total	$265,929

10. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities, surface leases and the Company's head office lease. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the nine months ended September 30, 2021 were between 4.5% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at September 30, 2021:

($ thousands)	Nine months ended September 30, 2021	Year Ended December 31, 2020
Balance, beginning of period	**$10,154**	$12,170
Lease additions	**2,350**	332
Leases acquired (note 7)	**1,624**	–
Interest expense	**596**	840
Lease payments	**(2,850)**	(3,188)
Balance, end of the period	**$11,874**	$10,154
Current portion	**$3,681**	$2,484
Long term portion	**$8,193**	$7,670

Undiscounted cash outflows relating to the lease liabilities are:

($ thousands)	Nine months ended September 30, 2021	Year Ended December 31, 2020
Less than 1 year	**$4,266**	$3,155
Years 2 and 3	**7,128**	6,140
Years 4 and 5	**2,972**	3,110
Thereafter	**1,836**	2,309
Total	**$16,202**	$14,714

11. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2021**	2020	**2021**	2020
Source/(use) of cash:				
Accounts receivable	**$(13,370)**	$(1,948)	**$(63,918)**	$17,303
Prepaid expenses and deposits	**523**	(511)	**(2,836)**	(354)
Accounts payable and accrued liabilities	**19,576**	(2,214)	**58,458**	(8,690)
Working capital acquired (note 7)	**–**	–	**10,646**	–
	$6,729	$(4,673)	**$2,350**	$8,259
Related to operating activities	**$243**	$(3,320)	**$(25,930)**	$10,131
Related to financing activities	**$ –**	$ –	**$(1,005)**	$ –
Related to investing activities	**$6,486**	$(1,353)	**$29,285**	$(1,872)

The following are included in cash provided by operating activities:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2021**	2020	**2021**	2020
Interest paid in cash on bank debt	**$5,837**	$2,451	**$12,813**	$6,133
Bank renewal fees	**424**	1	**1,085**	532
Interest paid on lease liabilities	**211**	206	**596**	644

12. Shareholders' equity:

a) Share capital:

At September 30, 2021, the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value. At September 30, 2021, Tamarack had issued and outstanding 406,431,217 Common Shares (December 31, 2020 – 262,776,395). No preferred shares have been issued.

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

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

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

On June 1, 2021, the Company issued 105,341,880 Common Shares as partial consideration in the Anegada Acquisition (note 7). Share issue costs in the amount of $0.5 million were incurred in association with the share issuance.

b) Treasury shares:

During the nine months ended September 30, 2021, the Company spent $4.9 million to purchase 2.1 million Common Shares to be used to settle stock options (the "Stock Options"), restricted share units ("RSUs") and performance share units ("PSUs") on the date of exercise. As at September 30, 2021, 655,989 Common Shares remain classified as treasury shares to be used for future settlements of Stock Options, RSUs and PSUs (December 31, 2020 – 746,742 Common Shares).

13. Net income (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except per share amounts)	**2021**	2020	**2021**	2020
Net income (loss)	**$20,032**	$(5,776)	**$250,060**	$(293,164)
Weighted average shares - basic	**406,152**	221,611	**335,913**	221,610
Weighted average shares - diluted	**414,342**	221,611	**344,072**	221,610
Net income (loss) per share-basic	**$ 0.05**	$(0.03)	**$ 0.74**	$(1.32)
Net income (loss) per share-diluted	**$ 0.05**	$(0.03)	**$ 0.73**	$(1.32)

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the three and nine months ended September 30, 2021, 12.1 million and 12.0 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs, PSUs and TAC Preferred Shares (as defined below) were included in the diluted weighted average number of Common Shares outstanding, respectively. For both the three and nine months ended September 30, 2020, 13.0 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs, PSUs and TAC Preferred Shares were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss.

14. Bank debt:

Tamarack currently has available a revolving credit facility in the amount of $470 million, a term credit facility in the amount of $100 million and an operating facility of $30 million (collectively, the “Facility”) with a syndicate of lenders. A total of $521.0 million was drawn as of September 30, 2021 (December 31, 2020 – $210.9 million). The interest rate applicable to the drawn amounts as of this date was 3.94%. The term credit facility is amortizing and reduces from $100 million to $75 million in December 2021, $40 million in March 2022 and nil in May 2022. The Company will, therefore, be required to pay any outstanding balances in excess of the term facility commitment amount on those dates. The revolving credit 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 total interest rate on the Facility is determined through a pricing grid that categorizes based on both a total amount drawn and a net debt-to-cash-flow ratio as defined in the Facility. The interest rate will vary depending on: the lending vehicle employed; the total loan value drawn; and the Company’s current net debt-to-cash-flow ratio. Interest on bankers’ acceptances (“BA”) and LIBOR (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 3.00% to a high of the banks’ posted rates plus 5.50%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks’ prime rates plus 2.00% to a high of the banks’ prime rates plus 4.50%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.25% on the undrawn portion of the Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates. As at September 30, 2021, the Facility was secured by a $1.2 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by May 31, 2022.

The Facility is governed by a Consolidated Net Debt to Cash Flow Ratio financial covenant as defined by the Amended and Restated Credit Agreement ("ARCA"). The consolidated net debt to cash flow ratio is defined in the ARCA as the ratio at the end of the quarter of (i) net debt – the working capital adjustment plus consolidated debt (bank and other) – divided by (ii) cash flow – the net income for the defined period adjusted for any non-cash items, acquisitions and dispositions. For the first four quarters, the cash flow period will be the most recent quarter annualized. Thereafter, cash flow will be represented by the prior twelve month's trailing cash flow. Subject to quarterly testing, the Consolidated Net Debt to Cash Flow Ratio threshold decreases across the term of the facility from 3.50:1.00 at the first test on September 30, 2021, 3.00:1.00 on December 31, 2021 and 2.50:1.00 on March 31, 2022 and thereafter. The first quarterly test completed for September 30, 2021 was in compliance and management's current 2021 and 2022 budget forecast future compliance with this covenant.

The Company manages its credit facility using a combination of prime rate loans, BA notes and US dollar denominated LIBOR loans. During the quarter ended September 30, 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 September 30, 2021, the Company had drawn US$245.0 million, fixed at notional amounts of $310.5 million through CCS maturing across the month of October 2021 (December 31, 2020 – the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS).

15. Share-based payments:

(a) The following table summarizes stock-based compensation expense relating to Stock Options, RSUs and PSUs:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2021**	2020	**2021**	2020
Non-cash stock- based compensation				
Stock Options	**$161**	$88	**$405**	$197
RSUs	**893**	871	**2,539**	2,552
PSUs	**610**	770	**3,804**	2,052
Total non-cash stock-based compensation:	**$1,664**	$1,729	**$6,748**	$4,801
Total capitalized costs	**(506)**	(189)	**(2,957)**	(715)
Total expensed non-cash stock-based compensation	**$1,158**	$1,540	**$3,791**	$4,086

(b) **Preferred share plan:**

At September 30, 2021, there are 740,307 (December 31, 2020 – 740,307) preferred shares of Tamarack Acquisition Corp. (the "TAC Preferred Shares") issued and outstanding. At September 30, 2021, the TAC Preferred Shares were fully vested and exchangeable into 711,834 (December 31, 2020 – 711,834) Common Shares at an exchange price of $3.12 per Common Share.

Under the terms of the Company's preferred share plan, a cashless settlement alternative is available, whereby holders of TAC Preferred Shares can either (i) elect to receive Common Shares by delivering cash to the Company in the amount of the TAC Preferred Shares, or (ii) elect to receive a number of Common Shares equivalent to the market value of the TAC Preferred Shares in excess of the TAC Preferred Shares at the exchange price of $3.12 per Common Share.

(c) **Options:**

Pursuant to the Company's stock option plan (the "Stock Option Plan") and the Company's performance and restricted share unit plan (the "PRSU Plan"), the Company may grant up to an aggregate of 28.5 million Stock Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at September 30, 2021, there was an aggregate of 14.1 million Stock Options, RSUs and PSUs issued and outstanding.

Stock Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.9 million Stock Options granted during the nine months ended September 30, 2021 (December 31, 2020 – 0.6 million).

The fair value of each Stock Option granted during the nine months ended September 30, 2021 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	Nine months ended September 30, 2021
Risk free rate (%)	**0.85**
Expected volatility (%)	**61**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**1.21**

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

	Number of Stock Options (thousands)	Weighted average exercise price
Outstanding, December 31, 2019	2,193	$3.01
Granted	559	1.13
Forfeited/expired	(848)	2.88
Outstanding, December 31, 2020	1,904	$2.51
Granted	868	2.33
Forfeited/expired	(148)	2.85
Outstanding, September 30, 2021	**2,624**	**$2.43**

The range of exercise prices of the Stock Options outstanding and exercisable at September 30, 2021 is as follows:

	Stock Options outstanding			Stock Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 0.64 – 2.50	1,203	$1.75	4.0	186	$1.13
$ 2.51 – 2.81	689	$2.60	2.7	416	$2.61
$ 2.82 – 3.44	732	$3.39	0.2	732	$3.39
$ 0.64 – 3.44	**2,624**	**$2.43**	**2.7**	**1,334**	**$2.83**

(d) **RSUs:**

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.2 million RSUs granted during the nine months ended September 30, 2021 (December 31, 2020 – 2.0 million).

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

The following table summarizes information about the RSUs:

	Number of RSUs (thousands)
Outstanding, December 31, 2019	6,987
Granted	1,986
Exercised	(3,363)
Forfeited	(245)
Outstanding, December 31, 2020	5,365
Granted	2,161
Exercised	(1,649)
Forfeited	(98)
Outstanding, September 30, 2021	**5,779**
Exercisable, September 30, 2021	**1,865**

(e) **PSUs:**

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 2.9 million PSUs awarded during the nine months ended September 30, 2021 (December 31, 2020 – 1.7 million).

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

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, December 31, 2019	2,157
Awarded	1,657
Forfeited	(250)
Outstanding, December 31, 2020	3,564
Awarded	2,918
Exercised	(516)
Forfeited	(310)
Outstanding, September 30, 2021	**5,656**
Earned, September 30, 2021	**2,401**
Exercisable, September 30, 2021	**808**

16. Commitments:

The following table summarizes the Company's commitments as at September 30, 2021:

($ thousands)	2021	2022	2023	2024	2025+
Bank debt(1)	$25,000	$75,000	$420,960	$ –	$ –
Lease(2)	56	229	229	229	172
Take or pay commitments(3)	933	4,023	3,894	–	–
Gas transportation(4)	642	2,539	947	272	11
Capital commitments(5)	–	52,261	70,172	–	–
Total	$26,631	$134,052	$496,202	$501	$183

(1) If not extended by May 31, 2022, the 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) Pipeline commitments to deliver a minimum of 636 m^3/d of crude oil/condensate and 455 m3/d of crude oil subject to a take-or-pay provision of $9.00/$m^3$ and $9.70/$m^3$, respectively, escalating approximately 2% per annum. The terms started on January 1, 2019 and last for 60 months.

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

(5) 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 $122.4 million is remaining to be incurred.

17. Contingency:

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

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

CORPORATE INFORMATION

Directors

John Rooney - Chairman [1][3][4]

Jeff Boyce[1][4]

John Leach[1][2]

Ian Currie[2][4]

Rob Spitzer[2][3]

Marnie Smith[1][3]

Brian Schmidt

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

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Kevin Screen
Chief Operating Officer

Martin Malek
VP Engineering

Christine Ezinga
VP Corporate Planning & Business Development

Scott Shimek
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Contact Information

Tamarack Valley Energy Ltd.
Jamieson Place
3300, 308 – 4th Avenue SW
Calgary, AB T2P 0H7
Telephone: 403 263 4440
Fax: 403 263 5551
www.tamarackvalley.ca