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, 2022 and 2021. This MD&A is dated and based on information available as at October 27, 2022 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, 2022 and 2021 and the audited consolidated financial statements for the year ended December 31, 2021. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2021, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The financial statements have been prepared in accordance with International Accounting Standards 34 "Interim Financial Reporting". The Company uses certain Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures in this MD&A. Certain financial measures are also presented on a per bbl, per boe, per mcf or per share basis that results in those measures considered as Supplemental Financial Measures. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" beginning on page 23. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Message to Shareholders

Tamarack delivered strong operational and financial results in Q3 2022. Despite the slowing economic growth outlook and deteriorating macroeconomic conditions which drove global oil prices lower in the third quarter, the underlying supply/demand dynamics with respect to commodity pricing remains constructive over a multi-year time horizon. However, management believes volatility is likely to persist due to high inflation levels, tightening monetary policies by major central banks, rising interest rates, geopolitical risk and the potential for renewed COVID-19 outbreaks and lockdowns.

Tamarack remains committed to sustainably growing long term free funds flow on a per share basis. Consistent with this strategy the Company successfully closed the previously announced acquisition of Deltastream Energy Corporation ("Deltastream") on October 13, 2022. Deltastream was a privately held pure-play Clearwater oil producer which held a leading economic drilling inventory of high-quality, long-life assets. The Deltastream assets add approximately 19,500 boe/d of current production, weighted approximately 94% to crude oil and natural gas liquids production. The Deltastream acquisition strategically positions Tamarack as the largest producer in the Clearwater oil fairway. Tamarack acquired all of the issued and outstanding common shares of Deltastream for total consideration of $1.425 billion consisting of 80 million common shares of Tamarack, $300 million of deferred acquisition notes and $825 million in cash.

The cash consideration of the acquisition was financed through a $100 million add-on offering to the Company's existing 7.25% senior unsecured sustainability linked notes due May 10, 2027 and a $137.3 million net equity financing; both of which closed in September of 2022. The remainder was drawn from Tamarack's new three-year $700 million sustainability linked covenant-based lending facility and a two-year $260 million term facility.

In conjunction with the Deltastream acquisition, Tamarack has increased its base monthly dividend by 25% to $0.0125 per share beginning with the November declaration. The increase in Tamarack's monthly cash dividend reflects the improvement in sustainable free funds flow per share the Company has generated both organically and through the strategic Clearwater acquisitions across 2022 which were accretive on the Company's long term 5-year plan pricing of US$55/bbl WTI and $2.50/GJ AECO.

Q3 2022 Operational and Financial Highlights

	Three months ended September 30,			Nine months ended September 30,		
	2022	2021	% change	**2022**	2021	% change
($ thousands, except per share)						
Total oil, natural gas and processing revenue	**329,304**	212,265	55	**1,035,394**	457,867	126
Cash flow from operating activities	**229,927**	100,558	129	**577,488**	179,247	222
Per share – basic	**$ 0.52**	$ 0.25	108	**$ 1.34**	$ 0.53	153
Per share – diluted	**$ 0.52**	$ 0.24	117	**$ 1.33**	$ 0.52	156
Adjusted funds flow (1)	**177,834**	102,486	74	**530,315**	216,179	145
Per share – basic (2)	**$ 0.40**	$ 0.25	60	**$ 1.23**	$ 0.64	92
Per share – diluted (2)	**$ 0.40**	$ 0.25	60	**$ 1.22**	$ 0.63	94
Net income	**124,793**	20,032	523	**294,757**	250,060	18
Per share – basic	**$ 0.28**	$ 0.05	460	**$ 0.68**	$ 0.74	(8)
Per share – diluted	**$ 0.28**	$ 0.05	460	**$ 0.68**	$ 0.73	(7)
Net debt (1)	**(286,762)**	(519,708)	(45)	**(286,762)**	(519,708)	(45)
Capital expenditures	**98,451**	69,978	41	**333,301**	149,487	123
Weighted average shares outstanding *(thousands)*						
Basic	**440,388**	406,152	8	**431,672**	335,913	29
Diluted	**443,351**	414,342	7	**435,053**	344,072	26
Share Trading *(thousands, except share price)*						
High	**$ 4.62**	$ 3.31	40	**$ 6.48**	$ 3.31	96
Low	**$ 3.28**	$ 2.05	60	**$ 3.28**	$ 1.25	162
Average daily share trading volume (thousands)	**3,745**	2,865	31	**3,890**	2,753	41
Average daily production						
Light oil (bbls/d)	**16,229**	19,405	(16)	**17,437**	14,720	18
Heavy oil (bbls/d)	**13,183**	5,438	142	**10,524**	4,275	146
NGL (bbls/d)	**3,659**	4,257	(14)	**3,769**	3,243	16
Natural gas (mcf/d)	**62,428**	72,935	(14)	**66,839**	62,171	8
Total (boe/d)	**43,476**	41,256	5	**42,870**	32,600	32
Average sale prices						
Light oil ($/bbl)	**111.80**	79.12	41	**119.53**	74.43	61
Heavy oil ($/bbl)	**89.30**	67.97	31	**99.48**	61.40	62
NGL ($/bbl)	**49.18**	33.67	46	**56.23**	36.37	55
Natural gas ($/mcf)	**6.27**	3.44	82	**6.59**	3.14	110
Total ($/boe)	**81.98**	55.73	47	**88.28**	51.27	72
Operating netback ($/Boe)						
Average realized sales	**81.98**	55.73	47	**88.28**	51.27	72
Royalty expenses	**(14.06)**	(8.97)	57	**(16.49)**	(7.51)	120
Net production and transportation expenses	**(13.12)**	(10.53)	25	**(12.74)**	(10.75)	19
Operating field netback ($/Boe) (2)	**54.80**	36.23	51	**59.05**	33.01	79
Realized commodity hedging loss	**(2.90)**	(6.21)	(53)	**(5.46)**	(5.62)	(3)
Operating netback ($/Boe) (2)	**51.90**	30.02	73	**53.59**	27.39	96
Adjusted funds flow ($/Boe) (2)	**44.46**	27.00	65	**45.31**	24.29	87

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

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

- Achieved quarterly production volumes of 43,476 boe/d in Q3/22, representing a 5% increase compared to the same period in 2021.
- Generated adjusted funds flow of $177.8 million in Q3/22 ($0.40 per share basic and diluted) compared to $102.5 million in the same period in 2021 ($0.25 per share basic and diluted) and $530.3 million for the nine months ended September 30, 2022 ($1.23 per share basic and $1.22 per share diluted) compared to $216.2 million in the same period in 2021 ($0.64 per share basic and $0.63 per share diluted).
- Generated free funds flow (see "Capital Management Measures"), excluding acquisition expenditures, of $79.4 million in Q3/22 and $197.0 million year to date.
- Generated net income of $124.8 million ($0.28 per share basic and diluted) and $294.8 million ($0.68 per share basic and diluted) for the three and nine months ended September 30, 2022 as compared to net income of $20.0 million ($0.05 per share basic and diluted) and $250.1 million ($0.74 per share basic and $0.73 per share diluted) in the same periods of 2021.
- To date the Company has paid or accrued $35.8 million to shareholders through dividends on its common shares, including $0.0083 per share for the first five months of 2022 and $0.01 per share for all dividends declared on and after June 15, 2022.
- Invested $93.5 million in exploration and development ("E&D") capital expenditures and $4.7 million on undeveloped land in the Clearwater and Charlie Lake areas during Q3/22.This contributed to the drilling of twenty-three (23.0 net) Clearwater oil wells and six (5.4 net) Charlie Lake oil wells.
- Exited the quarter with $286.8 million of net debt (see "Capital Management Measures"), inclusive of current taxes payable, and net debt to Q3/22 annualized adjusted funds flow (see "Capital Management Measures") of 0.4x.
- Delivered on the enhanced return of capital framework with the purchase of 3.1 million common shares under our NCIB for $12.8 million. Year to date the Company has repurchased 4.4 million shares for total consideration of $18.6 million.
- Successfully closed the disposition of certain assets in the Viking oil CGU for net consideration of approximately $59.5 million (inclusive of a $20.0 million promissory note at 12% per annum interest maturing on July 21, 2025). This is consistent with our portfolio rationalization strategy and focus on long term sustainable free funds flow growth.

Climate Change and Sustainability

Tamarack continues to consider the impact of climate change and the financial and operational challenges this global concern has had in 2022 and the continuing impact on the Company during the years ahead.

Climate Change

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

Emissions, carbon and other regulations impacting climate and climate related matters, are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board ("ISSB") was created on November 3, 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. On March 31, 2022, the ISSB issued exposure drafts *IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information"* and *IFRS S2 "Climate-related Disclosures",* which exposure drafts closed for comment on July 29, 2022. IFRS S1 *"sets out the overall requirements for disclosing sustainability-related financial information in order to provide primary users with a complete set of sustainability-related financial disclosures."* IFRS S2 *"sets out the requirements for identifying, measuring and disclosing climate-related risks and opportunities as part of an entity's general purpose financial reporting."* Responses to the consultation are currently being reviewed by the

ISSB. The exposure drafts do not currently disclose an effective date for the application of any future sustainability standards and accordingly, the Company is not able at this time to determine the impact on future financial statements that may result from these exposure drafts. In addition, the Canadian Securities Administrators have issued a proposed National Instrument ("NI 51-107") - Disclosure of Climate-related Matters. The cost to comply with these standards, and others, that may be developed or evolved over time, is not quantifiable at this time. Significant estimates and judgments have been made by management in the preparation of the financial statements in areas of property, plant and equipment, depletion, impairment and impairment reversal, reserves estimates, decommissioning obligations, credit facilities and share capital.

Sustainability

Tamarack is committed to the continued advancement of our ESG practices. As outlined in our 2022 Report on Sustainability Performance Target Progress released on September 30, 2022 Tamarack continues to make meaningful progress in our identified priority areas. In addition, Tamarack will release its third annual sustainability report in November 2022. This report will provide details on the Company's approach to sustainability, including our commitments to greenhouse gas emissions management and to continued Indigenous and community partnerships in the areas where we operate. The report will also highlight specific, measurable goals and targets related to key focus areas set by the Company.

Based on the Company's commitment and approach to sustainability, the Company amended its existing revolving bank facility to a Sustainability Linked Lending Facility ("SLL Facility') in late 2021 that incorporates sustainability-linked interest rate terms (see Credit Facilities on page 19). During the first quarter of 2022 the Company issued $200.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes ("SL Notes") due May 10, 2027 and an additional $100.0 million aggregate principal amount of SL Notes due May 10, 2027 in the third quarter of 2022 (see Senior Unsecured Notes on page 20).

Production

	Three months ended September 30,			Nine months ended September 30,		
	2022	2021	% change	**2022**	2021	% change
Production						
Light oil (bbls/d)	**16,229**	19,405	(16)	**17,437**	14,720	18
Heavy oil (bbls/d)	**13,183**	5,438	142	**10,524**	4,275	146
Natural gas liquids (bbls/d)	**3,659**	4,257	(14)	**3,769**	3,243	16
Natural gas (mcf/d)	**62,428**	72,935	(14)	**66,839**	62,171	8
Total (boe/d)	**43,476**	41,256	5	**42,870**	32,600	32
Percentage of oil and NGL	**76%**	71%	7	**74%**	68%	9

Average production for Q3/22 and the nine months ended September 30, 2022 increased 5% and 32%, respectively, compared to the same periods in 2021 due to the acquisitions that closed throughout 2022 and the 2021 and 2022 development programs, partially offset by expected declines of existing base production and the disposition of non-core Viking oil CGU assets in Q3/22 with an exit volume of approximately 2,000 boe/d. The Company's oil and NGL weighting for the three and nine months ended September 30, 2022 is 76% and 74%, higher by 7% and 9% respectively, as compared to the same periods in 2021 due to the acquisitions.

Petroleum and Natural Gas Sales

	Three months ended September 30,			Nine months ended September 30,		
	2022	2021	% change	**2022**	2021	% change
Revenue ($ thousands)						
Light oil	**$167,023**	$141,288	18	**$569,281**	$299,164	90
Heavy oil	**108,308**	34,005	219	**285,804**	71,651	299
Natural gas liquids	**16,551**	13,184	26	**57,853**	32,198	80
Natural gas	**36,028**	23,050	56	**120,197**	53,271	126
Total	**$327,910**	$211,527	55	**$1,033,135**	$456,284	126
Average realized price:						
Light oil ($/bbl)	**111.80**	79.12	41	**119.53**	74.43	61
Heavy oil ($/bbl)	**89.30**	67.97	31	**99.48**	61.40	62
Natural gas liquids ($/bbl)	**49.18**	33.67	46	**56.23**	36.37	55
Combined average oil and NGL ($/boe)	**95.93**	70.40	36	**105.39**	66.38	59
Natural gas ($/mcf)	**6.27**	3.44	82	**6.59**	3.14	110
Revenue ($/boe)	**81.98**	55.73	47	**88.28**	51.27	72
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**91.55**	70.55	30	**98.09**	64.85	51
Edm Par Differential (US$/bbl)	**2.05**	4.08	(50)	**1.84**	4.13	(55)
WCS differential (US$/bbl)	**19.86**	13.58	46	**15.73**	12.50	26
Edmonton Par (Cdn$/bbl)	**116.79**	83.76	39	**123.41**	75.91	63
Hardisty Heavy (Cdn$/bbl)	**93.52**	71.79	30	**105.54**	65.45	61
NYMEX monthly settlement (US$/mmbtu)	**8.20**	4.01	104	**6.77**	3.11	118
AECO daily index (Cdn$/mcf)	**4.00**	3.60	11	**5.24**	3.26	61
AECO monthly index (Cdn$/mcf)	**5.77**	2.47	134	**5.55**	2.75	102

During Q3 2022, revenue per boe from oil, natural gas and NGL sales for Q3/22 increased by 47% compared to Q3 2021 and 72% compared to year-to-date ("YTD") 2021, due to improved WTI, Edmonton Par differentials, realized heavy oil prices and natural gas prices and increased heavy oil production. The Company averaged realized light oil pricing of $111.80 per barrel, heavy oil pricing of $89.30 per barrel, NGL pricing of $49.18 per barrel and natural gas pricing of $6.27 per mcf. The realized pricing on all products increased from Q3 2021 when the Company averaged realized light oil pricing of $79.12 per barrel, heavy oil pricing of $67.97 per barrel, NGL pricing of $33.67 per barrel and natural gas pricing of $3.44 per mcf. The WTI benchmark price rose in Q3/22 averaging US$91.55 per bbl, a 30% increase over the WTI benchmark for the same period in 2021 of US$70.55 per bbl on concerns over global supply and the Russia-Ukraine conflict. The Edmonton Par light oil differential improved to an average of US$2.05 per bbl and the WCS heavy oil differential increased to an average of US$19.86 per bbl largely due to the United States Strategic Petroleum Reserve withdrawal with a significant portion being sour crude, compared to US$4.08 per bbl and US$13.58 per bbl, respectively, in Q3 2021. Realized NGL pricing improved by 46% over Q3 2021 due to improved benchmark pricing and negotiated differentials. Tamarack's realized natural gas price increased 82% to $6.27 per mcf in Q3 2022 from $3.44 per mcf in Q3 2021. The AECO daily benchmark price increased 11% to $4.00 per mcf in Q3 2022 from $3.60 per mcf in Q3 2021 while the NYMEX monthly settlement price increased 104% to US$8.20 per mmbtu in Q3 2022 from US$4.01 per mmbtu in Q3 2021. The overall increases in both benchmark prices and the Company's Q3 2022 realized price compared to the same quarter in the previous year was primarily due to increased global demand along with supply constraints globally and production discipline in North America.

YTD 2022, the Company averaged realized light oil pricing of $119.53 per barrel, heavy oil pricing of $99.48 per barrel, NGL pricing of $56.23 per barrel and natural gas pricing of $6.59 per mcf. The realized pricing on all products increased from YTD 2021 when the Company averaged realized light oil pricing of $74.43 per barrel, heavy oil pricing of $61.40 per barrel, NGL pricing of $36.37 per barrel and natural gas pricing of $3.14 per mcf. Benchmark pricing for WTI increased by 51% to US$98.09 per barrel for YTD 2022 compared to YTD 2021 on the global demand and supply factors discussed above. The YTD 2022 Edmonton Par light oil differential improved to an average of US$1.84 per barrel, and the YTD 2022 WCS heavy oil differential increased to an average of US$15.73 per barrel, compared to YTD 2021 US$4.13 per barrel and US$12.50 per barrel, respectively. YTD 2022 realized NGL pricing improved by 55% to $56.23 per barrel compared to YTD 2021 of $36.37 per barrel on improved benchmark pricing and negotiated differentials. Tamarack's YTD 2022 realized natural gas price increased 110% to $6.59 per mcf from $3.14 per mcf. The YTD 2022 AECO daily benchmark price increased 61% to $5.24 per mcf from $3.26 per mcf while the YTD 2022 NYMEX monthly settlement price increased 118% to US$6.77 per mmbtu from US$3.11 per mmbtu on strong global liquified natural gas demand.

Risk Management

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, 2022, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the tables below.

West Texas Intermediate and Differential Crude Oil Derivatives

	Q4 2022				Q1 2023				Q2 2023				Q3 2023				Q4 2023			
WTI Put																				
Volume (bbls/d)	**4,250**				**6,000**				**2,000**				**-**				**-**			
Average Put/Premium (USD/bbl)	56.43	3.18			55.00	2.99			55.00	2.90			-	-			-	-		
WTI 2-way Collar																				
Volume (bbls/d)	**12,000**				**11,000**				**11,500**				**8,500**				**1,500**			
Average Put/Call/Premium (USD/bbl)	57.48	106.18	1.95		66.59	108.44	2.27		67.63	110.89	2.57		67.06	102.67	2.88		68.00	92.12	3.00	
Volume (bbls/d)	**800**				**-**				**-**				**-**				**-**			
Average Put/Call/Premium (CAD/bbl)	80.00	100.83	-		-	-	-		-	-	-		-	-	-		-	-	-	
WTI 3-way Collar (Reverse)																				
Volume (bbls/d)	**750**				**-**				**-**				**-**				**-**			
Average Put/Call/Sold Put/Premium (USD/bbl)	55	70	74	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WTI Fixed Price																				
Volume (bbls/d)	**500**				**-**				**-**				**-**				**-**			
Average Fixed Price (USD/bbl)	87.25				-				-				-				-			
Volume (bbls/d)	**500**				**-**				**-**				**-**				**-**			
Average Fixed Price (CAD/bbl)	88.25				-				-				-				-			
Mixed Sweet Blend Differential (MSW)																				
Volume (bbls/d)	**9,000**				**-**				**-**				**-**				**-**			
Average Fixed Price (USD/bbl)	(3.46)				-				-				-				-			
Western Canadian Select Differential (WCS)																				
Volume (bbls/d)	**6,500**				**-**				**-**				**-**				**-**			
Average Fixed Price (USD/bbl)	(12.12)				-				-				-				-			

Natural Gas Derivatives

	Summer 22[(1)]	Nov-Dec 22	Winter 22-23[(2)]	Summer 23[(1)]
AECO 5A Swap				
Volume (GJ/d)	**31,500**	**1,500**	**10,000**	**-**
Average Fixed Price (CAD/GJ)	2.46	3.17	3.85	-
AECO - NYMEX Basis				
Volume (mmbtu/d)	**-**	**-**	**-**	**15,000**
Average Fixed Price (USD/mmbtu)	-	-	-	1.88
AECO 7A Collar				
Volume (GJ/d)	**-**	**-**	**20,000**	**-**
Average Put/Call (CAD/GJ)	- -	- -	3.65 6.14	- -
NYMEX Collar				
Volume (mmbtu/d)	**-**	**-**	**-**	**15,000**
Average Put/Call (USD/mmbtu)	- -	- -	- -	4.58 7.24

(1) Summer runs from April 1 to October 31 of the given year.
(2) Winter runs from November 1 to March 31 of the given year.

Foreign Exchange Derivatives

	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023
CAD/USD Put					
Amount (USD/month)	**$13,000,000**	**-**	**-**	**-**	**-**
Average Put/Premium (CAD/USD)	1.3314 0.0101	- -	- -	- -	- -
CAD/USD Collar					
Amount (USD/month)	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$1,000,000**
Average Put/Call (CAD/USD)	1.2500 1.3420	1.2500 1.3420	1.2500 1.3420	1.2500 1.3420	1.2500 1.3420
CAD/USD Variable Rate Collar					
Amount (USD/month)	**$10,000,000**	**-**	**-**	**-**	**-**
Average Put/Call (CAD/USD)	1.34 1.44 1.37	- - -	- - -	- - -	- - -
CAD/USD Swap					
Amount (USD/month)	**$9,000,000**	**-**	**-**	**-**	**-**
Average Fixed Price (CAD/USD)	1.3546	-	-	-	-
CAD/USD Target Average Rate Forward[(1)]					
Amount (USD/month)	**$500,000**	**-**	**-**	**-**	**-**
Average Fixed Price (CAD/USD)	1.2640	-	-	-	-

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

Interest Rate Derivatives

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

At September 30, 2022, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net asset value of $4.1 million (December 31, 2021 – $13.1 million net liability) recorded on the balance sheet. The Company recorded an unrealized gain of $47.8 million and a realized loss of $11.6 million in earnings for the three months ended September 30, 2022, compared to an unrealized loss of $2.2 million and a realized loss of $23.6 million during the same period in 2021. The Company recorded an unrealized gain of $32.1 million and a realized loss of $63.9 million in earnings for the nine months ended September 30, 2022, compared to an unrealized loss of $33.0 million and a realized loss of $50.1 million during the same period in 2021. The Company manages credit risk for these contracts by engaging with a variety of counterparties, all of which are investment grade banking institutions or large purchasers of commodities. All counterparties have been assessed for credit worthiness.

Subsequent to September 30, 2022, the Company has entered into the financial contracts noted in the tables below.

West Texas Intermediate and Differential Crude Oil Derivatives

	Nov/Dec 2022			Q1 2023			Q2 2023			Q3 2023			Q4 2023		
WTI 2-way Collar															
Volume (bbls/d)		**-**			**10,000**			**14,500**			**12,750**			**5,500**	
Average Put/Call/Premium (USD/bbl)	-	-	-	77.50	94.25	3.00	70.50	98.47	3.00	68.00	95.27	3.00	68.00	89.75	3.00
WTI Fixed Price															
Volume (bbls/d)		**12,500**			**1,000**			**-**			**-**			**-**	
Average Fixed Price (USD/bbl)		84.85			80.89			-			-			-	

Subsequent to September 30, 2022, the Company has assumed the financial contracts noted in the tables below as part of the Deltastream acquisition.

West Texas Intermediate and Differential Crude Oil Derivatives

	Q4 2022				Q1 2023				Q2 2023				Q3 2023				Q4 2023			
WTI 2-way Collar																				
Volume (bbls/d)		**1,775**				**1,050**				**1,050**				**850**				**850**		
Average Put/Call/Premium (CAD/bbl)	79.03	103.57	-		82.90	110.94	-		82.90	110.94	-		80.44	108.64	-		80.44	108.64	-	
WTI 3-way Collar																				
Volume (bbls/d)		**500**				**-**				**-**				**-**				**-**		
Average Put/Call/Sold Call/Premium (CAD/bbl)	44	57	76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WTI Fixed Price																				
Volume (bbls/d)		**1,925**				**300**				**300**				**200**				**200**		
Average Fixed Price (CAD/bbl)		87.99				94.23				94.23				91.75				91.75		
Western Canadian Select Differential (WCS)																				
Volume (bbls/d)		**3,400**				**1,000**				**1,000**				**700**				**700**		
Average Fixed Price (CAD/bbl)		(17.80)				(18.66)				(18.66)				(19.29)				(19.29)		

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, 2022, the Company held no physical commodity contracts. Subsequent to September 30, 2022, the Company has not entered into any physical commodity contracts.

Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2022	2021	% change	**2022**	2021	% change
Royalty expenses ($ thousands)	**$56,256**	$34,045	65	**$192,990**	$66,849	189
$/boe	**14.06**	8.97	57	**16.49**	7.51	120
Percent of sales (%)	**17**	16	6	**19**	15	27

Royalties as a percentage of revenue for the three and nine months ended September 30, 2022 were higher than the same periods in 2021, due to the sliding scale nature of some oil royalties, which increases the percentage during periods of high commodity prices, and the addition of the gross overriding royalties ("GORRs") in conjunction with the acquisitions that closed in 2021 and 2022. The Company expects royalty rates as a percentage of revenue for the last quarter of 2022 to increase to the 20% to 22% range based on current forecast commodity pricing levels and increased production from lands subjected to GORRs.

On an absolute basis, royalty expense was higher in Q3/22 and the nine months ended September 30, 2022, compared to same periods in 2021 due to an increase in commodity prices, production and GORRs.

Net Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2022**	2021	% change	**2022**	2021	% change
Production expenses	**$42,347**	$33,437	27	**$122,255**	$83,037	47
Less: processing income	**1,394**	738	89	**2,259**	1,583	43
Total net production expenses [1]	**$40,953**	$32,699	25	**$119,996**	$81,454	47
Total ($/boe) [2]	**$10.24**	$8.62	19	**$10.25**	$9.15	12

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

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

For the three and nine months ended September 30, 2022, per unit net production expenses (see "Non-IFRS Financial Ratios") were higher compared to the same periods in 2021. This resulted from the impact of general economic inflationary pressures on production related expenses in the first three quarters of 2022. The Company believes inflationary pressures will continue throughout the remainder of 2022.

For the three and nine months ended September 30, 2022, on an absolute basis gross and net production expenses were higher compared to the same periods in 2021 due to higher production and higher per unit net production expenses as discussed above.

Transportation Expense

($ thousands, except per boe)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Transportation expense - gas	**$2,890**	$2,799	3	**$8,737**	$5,798	51
Transportation expense - oil	**8,621**	4,466	93	**20,406**	8,432	142
Total transportation expense	**$11,511**	$7,265	58	**$29,143**	$14,230	105
Total ($/boe)	**$2.88**	$1.91	51	**$2.49**	$1.60	56

For the three and nine months ended September 30, 2022, per unit transportation expenses were higher compared to the same periods in 2021. The increase in oil transport was primarily driven by an increase in heavy oil deliveries as this production has the highest per barrel cost in order to reach a variety of terminals and maximize netbacks. Additionally, fuel surcharges remained high in the third quarter of 2022 relative to the comparative period. The increase in natural gas transportation expense was primarily a result of higher fuel charges.

For the three and nine months ended September 30, 2022, total transportation expenses were higher compared to the same period in 2021 due to higher production and a larger proportion of the total production being heavy oil. Fuel surcharges continued to be a prevalent cost in Q3/22 for both liquids and natural gas.

Operating Netback

($/boe)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Average realized sales	**$81.98**	$55.73	47	**$88.28**	$51.27	72
Royalty expenses	**(14.06)**	(8.97)	57	**(16.49)**	(7.51)	120
Net production expenses [1]	**(10.24)**	(8.62)	19	**(10.25)**	(9.15)	12
Transportation expense	**(2.88)**	(1.91)	51	**(2.49)**	(1.60)	56
Operating field netback [1]	**$54.80**	$36.23	51	**$59.05**	$33.01	79
Realized hedging loss	**(2.90)**	(6.21)	(53)	**(5.46)**	(5.62)	(3)
Operating netback [1]	**$51.90**	$30.02	73	**$53.59**	$27.39	96

(1) Non-IFRS Financial Ratio; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

For the three and nine months ended September 30, 2022, operating netbacks per boe (see “Non-IFRS Financial Ratios”) were higher than the same periods in 2021 primarily due to the higher commodity prices realized in 2022, partially offset by higher net production expenses, higher transportation expense and higher royalties.

General and Administrative ("G&A") Expenses

($ thousands, except per boe)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Gross costs	**$7,745**	$6,362	22	**$25,576**	$16,988	51
Capitalized costs and recoveries	**(1,934)**	(1,362)	42	**(5,308)**	(3,968)	34
General and administrative costs	**$5,811**	$5,000	16	**$20,268**	$13,020	56
Total ($/boe)	**$1.45**	$1.32	10	**$1.73**	$1.46	18

Net G&A costs on a per boe basis for the three and nine months ended September 30, 2022 were higher compared to the same periods in 2021, due to increased staffing levels and general economic inflationary pressures. The Company believes inflationary pressures will continue throughout the remainder of 2022.

For the three and nine months ended September 30, 2022 gross and net G&A costs were higher compared to the same periods in 2021, due to increased staffing levels and other Company growth-related cost increases. A donation of $1.0 million to support humanitarian efforts to aid the people of Ukraine was made during the nine-month period ended September 30, 2022.

Stock-Based Compensation Expense

($ thousands, except per boe)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Stock Options	**$40**	$161	(75)	**$135**	$405	(67)
RSUs	**1,219**	893	37	**3,114**	2,539	23
PSUs	**335**	610	(45)	**1,272**	3,804	(67)
Equity settled	**$1,594**	$1,664	(4)	**$4,521**	$6,748	(33)
RSUs	**$(360)**	$ –	–	**$151**	$ –	–
PSUs	**(839)**	–	–	**–**	–	–
RIAs	**356**	–	–	**675**	–	–
PIAs	**189**	–	–	**594**	–	–
Cash settled	**$(654)**	$ –	–	**$1,420**	$ –	–
Total capitalized costs	**$(531)**	$(506)	5	**$(2,196)**	$(2,957)	(26)
Total expensed stock-based compensation	**$409**	$1,158	(65)	**$3,745**	$3,791	(1)
Total ($/boe)	**$0.10**	$0.31	(68)	**$0.32**	$0.43	(26)

Pursuant to the Company's stock option plan (the "Stock Option Plan"), the Company's performance and restricted share unit plan (the "PRSU Plan") and the Company's cash award incentive plan (the "CAI Plan"), the Company may grant up to an aggregate of 33.3 million Stock Options, Restricted Share Units ("RSUs"), Performance Share Units ("PSUs"), Restricted Incentive Awards ("RIAs") and Performance Incentive Awards ("PIAs") to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable.

Effective March 9, 2022, PRSUs granted prior to that date for the Company's "Insiders" (Insiders as defined in securities legislation, excluding Directors of the Company) upon vesting will be settled in cash. For all other non-insiders participating in the PRSU Plan, the PRSU awards will continue to be equity-settled. The value of the share awards to Insiders PRSUs, granted prior to March 9, 2022, were reclassified from Contributed Surplus to Other Liabilities on the Condensed Consolidated Interim Balance Sheet. The fair value of PRSUs that are accounted for as cash-settled transactions are subsequently adjusted to the underlying Common Share price at each period end.

On March 9, 2022, the Company's Board of Directors approved the implementation of the CAI Plan which will be used for future RIA and PIA grants that will be cash-settled. Both insiders and non-insiders are eligible for grants of awards under the CAI Plan.

Stock-based compensation expense related to Stock Options, RSUs, PSUs, RIAs and PIAs for the three and nine months ended September 30, 2022 were lower compared to the same periods in 2021 primarily due to a reduced number of equity-settled grants and the impact of common share prices on the cash-settled units as compared to the same period in 2021.

During the three months ended September 30, 2022, the Company issued 0.1 million RSUs, 0.03 million PSUs, 0.06 million RIAs and 0.2 million PIAs compared to 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 during the same period in 2021.

During the nine months ended September 30, 2022, the Company issued 1.5 million RSUs, 1.3 million PSUs, 0.5 million RIAs and 1.2 million PIAs compared to 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 during the same period in 2021.

For the three and nine months ended September 30, 2022, the Company paid $0.2 million and $6.7 million, respectively, for the settlement of RSU and PSU exercises.

Finance Expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2022**	2021	% change	**2022**	2021	% change
Interest and fees on credit facilities	**$4,591**	$6,261	(27)	**$14,456**	$13,898	4
Interest and fees on senior unsecured notes	**4,102**	–	–	**10,121**	–	–
Interest on lease liabilities	**185**	211	(12)	**564**	596	(5)
Accretion on government loan	**96**	–	–	**282**	–	–
Unrealized loss (gain) on foreign exchange	**(10,500)**	(6,033)	74	**343**	1,426	(76)
Unrealized loss (gain) on cross-currency swap	**9,884**	6,039	64	**(292)**	(1,410)	(79)
Accretion of decommissioning obligations	**2,061**	1,330	55	**5,085**	3,474	46
Total finance expense	**$10,419**	$7,808	33	**$30,559**	$17,984	70
Total ($/boe)	**$2.60**	$2.06	26	**$2.61**	$2.02	29
Average drawings on credit facilities	**$100,921**	$512,132	(80)	**$262,856**	$364,015	(28)
Average drawings on senior unsecured notes	**$225,850**	$ –	–	**$183,684**	$ –	–

Total finance expense for the three and nine months ended September 30, 2022 was higher than the same periods in 2021 due to higher interest rates on average drawings on the SLL facility and the interest on SL Notes issued in the first and third quarters of 2022. Canadian interest rates have increased in 2022 compared to the same periods in 2021.The interest rate on SL Notes issued in Q1/22 and Q3/22 is higher than rates on revolving borrowings. Interest and fees on the SLL facility and on SL Notes includes the amortization of fees associated with the review and renewal of the SLL facility and the issuance of the SL Notes.

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

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2022**	2021	% change	**2022**	2021	% change
Depletion and depreciation	**$77,549**	$72,463	7	**$223,351**	$149,770	49
Amortization of undeveloped leases	**845**	196	331	**1,884**	518	264
Total	**$78,394**	$72,659	8	**$225,235**	$150,288	50
Depletion and depreciation ($/boe)	**$19.39**	$19.09	2	**$19.08**	$16.83	13
Amortization ($/boe)	**0.21**	0.05	320	**0.16**	0.06	167
Total ($/boe)	**$19.60**	$19.14	2	**$19.24**	$16.89	14

For the three and nine months ended September 30, 2022, DD&A expense per boe was higher relative to the same periods in 2021. The increase was due to acquisitions that closed in the first two quarters of 2022 that have a higher DD&A expense per boe than the corporate average and the impact of the impairment reversals that were taken in Q2/21 and Q4/21 resulting in higher net book value of assets to be depleted in the first nine months of 2022. For the three and nine months ended September 30, 2021, DD&A expense per boe was partially reduced by the impact of the impairment charges taken in both Q1/20 and Q4/20, which were partially reversed by the impairment reversal of $300.0 million taken in Q2/21, 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, 2022 due to higher production and higher DD&A expense per boe.

Impairment of Property, Plant and Equipment

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

For the three and nine month periods ended September 30, 2022 there were no indicators of impairment or reversal of impairment identified on any of the Company’s CGUs within property, plant and equipment and no impairment or reversal of impairment test was performed which is consistent with the September 30, 2021 assessment.

For the nine months ended September 30, 2021, an 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 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

For the three and nine months ended September 30, 2022, the Company recorded current income tax expense of $19.9 million and $53.2 million, respectively (September 30, 2021 – $nil current income tax expense for both the three and nine month periods then ended) based on current full year estimates of commodity prices, forecast taxable income, existing tax pools and planned capital expenditures. The Company is not required to pay any cash income taxes related to the current income tax expense for the full year ended December 31, 2022 until Q1/23.

For the three and nine months ended September 30, 2022, the Company recorded deferred income tax expense of $20.3 million and $39.0 million, respectively (September 30, 2021 - $5.7 million and $78.3 million, respectively).

Adjusted Funds Flow and Net Income

($ thousands, except per share amounts)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Cash flow from operating activities	**$229,927**	$100,558	129	**$577,488**	$179,247	222
Current income tax expense	**(19,894)**	–	–	**(53,236)**	–	–
Decommissioning expenditures	**2,951**	1,046	182	**5,429**	2,892	88
Transaction costs	**–**	1,125	(100)	**–**	8,110	(100)
Changes in non-cash working capital	**(35,150)**	(243)	14,365	**634**	25,930	(98)
Adjusted funds flow (1)	**$177,834**	$102,486	74	**$530,315**	$216,179	145
Per share - basic (2)	**$0.40**	$0.25	60	**$1.23**	$0.64	92
Per share - diluted (2)	**$0.40**	$0.25	60	**$1.22**	$0.63	94
Net income	**$124,793**	$20,032	523	**$294,757**	$250,060	18
Per share - basic	**$0.28**	$0.05	460	**$0.68**	$0.74	(8)
Per share - diluted	**$0.28**	$0.05	460	**$0.68**	$0.73	(7)

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

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

Adjusted funds flow (see "Non-IFRS Financial Measures") and cash flow from operating activities for the three and nine months ended September 30, 2022 were higher compared to the same periods in 2021. This was primarily due to an increase in revenue resulting from additional production due to acquisitions completed in the first half of 2022 and higher commodity prices, partially offset by the disposition of non-core Viking oil CGU assets in Q3/22, a realized hedging loss in 2022, higher production and transportation costs and higher royalty expense.

The Company recorded net income of $124.8 million ($0.28 per share basic and diluted) and $294.8 million ($0.68 per share basic and diluted) during the three and nine months ended September 30, 2022 compared to net income of $20.0 million ($0.05 per share basic and diluted) and $250.1 million ($0.74 per share basic and $0.73 per share diluted) in the same periods in 2021.

The increase in net income for the three and nine months ended September 30, 2022 as compared to the same periods in 2021 is primarily due to an increase in revenue and unrealized hedging gains partially offset by higher royalty costs, higher production and transportation costs, higher general and administrative costs, higher depletion, depreciation and amortization costs and higher income tax expense.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2022**	2021	% change	**2022**	2021	% change
Land	**$4,720**	$4,158	14	**$52,275**	$6,585	694
Geological and geophysical	**32**	68	(53)	**301**	403	(25)
Drilling and completion	**72,161**	48,316	49	**215,413**	106,480	102
Equipment and facilities	**19,607**	16,086	22	**59,837**	31,747	88
Capitalized G&A	**1,718**	1,197	44	**4,812**	3,370	43
Office equipment	**213**	153	39	**663**	902	(26)
Total capital expenditures	**$98,451**	$69,978	41	**$333,301**	$149,487	123

During the third quarter of 2022, the Company drilled, completed and equipped, twenty-three (23.0 net) Clearwater oil wells and six (5.4 net) Charlie Lake oil wells.

For the nine months ended September 30, 2022, the Company drilled, completed and equipped sixty (60.0 net) Clearwater oil wells, sixteen (15.2 net) Charlie Lake oil wells, thirteen (13.0 net) Viking oil wells and five (5.0 net) water source and injector wells.

Included in land for the three and nine months ended September 30, 2022 is approximately $2.0 million and $45.1 million, respectively, of undeveloped prospective land additions in the Greater Peavine Clearwater area, that have been added to exploration and evaluation assets.

Included in equipment and facilities expenditures for the three and nine months ended September 30, 2022 are expenditures of approximately $1.3 million and $4.0 million, respectively (net of government assistance of approximately $0.6 million and $1.5 million, respectively, for the three and nine months ended September 30, 2022) related to the Company's Nipisi gas conservation project to eliminate the venting and incineration of solution gas into the atmosphere in furtherance of the Company's sustainability initiatives and reducing greenhouse gas emissions. Total estimated Nipisi gas conservation project capital spending is estimated to be approximately $11.9 million. In connection with this project the Company has recorded approximately $10.7 million of combined Federal Government of Canada Emissions Reduction Fund ("ERF") and Province of Alberta Methane Technology Implementation Program ("MTIP") funding, of which $4.3 million is recognized as a government loan as at September 30, 2022, under the terms of the ERF agreement. Total MTIP non-repayable government grant funding is $1.78 million. Total ERF government grant funding is estimated to be approximately $8.9 million, of which 65% is repayable under the terms of the ERF agreement. The ERF agreement includes scheduled repayments for the repayable funding of approximately $0.6 million on March 31, 2025, $1.9 million on March 31, 2026 and a final payment of $3.3 million on March 31, 2027. The repayable government loan funding will be interest-free based on the Company's compliance with the terms and conditions of the ERF funding agreement and all repayments made in accordance with the above noted repayment schedule.

Acquisitions and Dispositions

Acquisitions:

On June 10, 2022 the Company completed the Rolling Hills Energy Ltd., Southern Clearwater oil acquisition for total cash consideration of $49.3 million, including $2.8 million of capitalized transaction costs, and the issuance of 9.3 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $6.34 per common share, the total consideration was approximately $108.1 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. Oil and natural gas 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	$	127,704
Current assets		13,694
Current liabilities		(13,689)
Risk management contracts		(14,873)
Decommissioning obligations		(4,701)
Net assets acquired	**$**	**108,135**
Purchase consideration:		
Cash consideration	$	49,321
Share consideration (9,276,644 common shares)		58,814
Total purchase consideration	**$**	**108,135**

On February 15, 2022 the Company completed the Crestwynd Exploration Ltd., Southern Clearwater oil acquisition for total cash consideration of $98.9 million including $4.4 million of capitalized transaction costs and the issuance of 26.3 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $4.92 per common share, the total consideration was approximately $228.3 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. Oil and natural gas 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	$	228,065
Current assets		15,472
Current liabilities		(12,306)
Decommissioning obligations		(2,917)
Net assets acquired	**$**	**228,314**
Purchase consideration:		
Cash consideration	$	98,926
Share consideration (26,298,389 common shares)		129,388
Total purchase consideration	**$**	**228,314**

Dispositions:

For the nine months ended September 30, 2022 the Company disposed of a gross overriding royalty (between 2% and 5%) on a select portion of the Clearwater and Charlie Lake properties for consideration of $14.9 million and recorded a gain on disposition of $2.2 million.

On July 21, 2022 the Company disposed of non-Core Viking oil CGU assets for net consideration of approximately $59.5 million (inclusive of a $20.0 million promissory note at 12% interest maturing on July 21, 2025) and recorded a gain on disposition of $2.7 million.

The Company also disposed of non-core undeveloped land for proceeds of $0.6 million.

Share Capital

	September 30, 2022		December 31, 2021	
($ thousands)	**Number**	**Amount**	Number	Amount
Balance, opening	406,938,099	$1,242,392	262,776,395	$876,124
Issue of common shares - cash	38,334,100	143,753	33,333,300	75,000
Issue of common shares - acquisitions	35,575,033	188,202	110,230,769	290,427
Issue of common shares - cash on stock options	–	–	481,667	1,623
Issue of common shares - Option, RSU and PSU exercise	3,446,434	–	4,047,343	–
Issue on settlement of preferred shares	–	–	307,025	1,104
Purchase of common shares - cancellation	(4,362,700)	(14,375)	–	–
Return of common shares to treasury	–	(2,646)	–	–
Purchase of common shares - Option, RSU and PSU exercise	(3,529,100)	–	(4,238,400)	–
Transfer on stock option exercise	–	–	–	1,023
Share issue costs, net of tax (2022 - $1,475; 2021 - $869)	–	(4,937)	–	(2,909)
Balance, ending	476,401,866	$1,552,389	406,938,099	$1,242,392

(thousands)	**October 27, 2022**	**September 30, 2022**	December 31, 2021
Common shares outstanding	**556,402**	476,402	406,938
Common shares held in treasury	**539**	539	938
Options outstanding - non-cash settled	**1,404**	1,404	2,142
RSUs outstanding - equity-settled	**3,264**	2,757	4,703
PSUs outstanding - equity-settled	**1,943**	1,679	4,874

On September 27, 2022 the Company issued 38,334,100 shares at $3.75 per common share for gross proceeds of $143.8 million. Share issue costs in the amount of $6.4 million were incurred in association with the private placement.

Liquidity and Capital Resources

($ thousands)	September 30, 2022	December 31, 2021
Working capital deficiency (surplus) (1)	**$15,073**	$(15,253)
Notes receivable	**(20,000)**	–
Credit facilities	**–**	477,437
Senior unsecured notes	**287,379**	–
Government loan	**4,310**	1,100
Net debt (1)	**$286,762**	$463,284
Quarterly adjusted funds flow (1)	**$177,834**	$124,080
Annualized factor	**4**	4
Annualized adjusted funds flow (1)	**$711,336**	$496,320
Net debt to annualized adjusted funds flow (1)	**0.4x**	0.9x

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

Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by managing capital spending levels as appropriate to respond to changes in realized commodity prices and through the systematic hedging program using both financial derivatives and physical delivery contracts to mitigate risk. The Company generally relies on adjusted funds flow and its credit facility to fund its capital requirements, return of capital and provide liquidity.

Tamarack's net debt, including working capital deficiency (surplus) (see "Capital Management Measures"), totaled $286.8 million as at September 30, 2022. This compares to the Company's net debt of $519.7 million as at September 30, 2021 and $463.3 million as at December 31, 2021. Tamarack's Q3/22 net debt to annualized adjusted funds flow ratio (see "Capital Management Measures") was 0.4 times.

The Company's $98.5 million investment in capital additions during Q3/22 was fully funded by Tamarack's adjusted funds flow (see "Capital Management Measures") of $177.8 million. The decrease in the Company's net debt of $176.5 million as compared to December 31, 2021 is primarily due to the generation of funds flow to pay down the SLL facility, cash proceeds from the Viking oil CGU disposition, and net proceeds from issuing common shares to be used to partially fund the Deltastream acquisition which closed on October 13, 2022.

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

Pursuant to the Company's approved NCIB, the Company is permitted to purchase up to 20.4 million Common Shares over a period of twelve months commencing on November 3, 2021. The Company plans to renew its existing NCIB for an additional twelve-month period. During the nine months ended September 30, 2022, the Company purchased and cancelled 4.4 million Common Shares at an average price of $4.26 per Common Share, for a total repurchase cost of $18.6 million. For the year ended December 31, 2021 the Company did not purchase and cancel any Common shares.

During the nine months ended September 30, 2022, the Company paid $31.0 million related to its monthly cash dividends on its common shares of $0.0083 per share for the first five months of 2022 and $0.01 per share for all dividends declared on and after June 15, 2022 and accrued the dividend payable of $4.8 million on its common shares of $0.01 per share for the dividend declared on September 15, 2022.

The Company's Board of Directors declared the monthly cash dividend of $0.01 per share on October 15, 2022 payable on November 15, 2022 to shareholders of record at the close of business on October 31, 2022.

These monthly cash dividends are designated as "eligible dividends" for Canadian income tax purposes.

Credit Facilities

As at September 30, 2022 the principal amount of borrowings outstanding under our sustainability-linked lending facility ("SLL facility") was $nil, as a result of $39.5 million of net cash proceeds from the Viking oil CGU disposition, the issuance of an additional $100.0 million of SL Notes, net proceeds of $137.3 million from the issuance of common shares and the generation of funds flow in the current quarter. The net proceeds of issuance of the SL Notes and the common shares were used to partially fund the Deltastream acquisition which closed on October 13, 2022.

Subsequent to September 30, 2022 the Company established a new three-year covenant-based SLL facility, replacing the existing SLL facility, which increased the SLL facility to $700 million and is paired with a $260 million two-year secured amortizing term-loan ("Term Facility") from a syndicate of lenders ("Syndicated Facility"). The Syndicated Facility is secured by a $2.0 billion debenture with fixed coverage over all the assets of the Company. The SLL portion of the facility bears interest at the applicable rate for the borrowing employed plus a credit margin based on the senior debt to EBITDA ratio of the Company.

As the SLL facility is a covenant-based facility, it is not contingent on the reserve base of the Company and not subject to annual or semi-annual redeterminations. The SLL facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower. There are no mandatory principal repayments required prior to maturity.

The SLL facility contains commercial covenants in addition to financial covenants detailed below.

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

- Greenhouse Gas Emissions Intensity: 39% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline, with a significant decrease in 2021 and more ratable 5% decreases through 2022 to 2025. This SPT exceeds the previous set target due to 2021 acquisitions and positive progress in emissions reductions to date.
- Decommissioning Management: committed annual capital investment in abandonment, remediation and reclamation activities at 150% of the Alberta Energy Regulator inventory reduction voluntary closure program targets. This target is equivalent to ~4.33% of inactive liabilities in 2021 with a 5% annual escalation.
- Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025 with annual milestones and minimum of two additions each year.

The Term Facility is a non-revolving facility with a maturity date of October 13, 2024 and may be extended for a single twelve-month term at the request of the borrower and the discretion of the lenders. Minimum quarterly amortization payments are required beginning in January 2023 with the balance due and payable at maturity. The term-loan portion of the facility bears interest at the applicable rate for the borrowing employed plus a fixed margin rate.

Financial Covenants:

The following table summarizes the financial covenants applicable to the SLL Facility after September 30, 2022:

Covenant Description	Covenant[5]
Total Debt[1] to EBITDA[2] Ratio	3.0:1.0
Senior Debt[3] to EBITDA[2] Ratio	2.5:1.0
Debt Service Coverage[4] Ratio	1.5:1.0

(1) "Total Debt" is calculated in accordance with the credit facility agreements as all Debt of the Company excluding capitalized lease obligations and Letters of Credit and including indebtedness under the deferred acquisition notes issued on closing of the Deltastream acquisition.

(2) "EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on the previous four quarters including the impact of material acquisitions as if they had occurred at the beginning of the four quarters.

(3) "Senior Debt" is calculated in accordance with the credit facility agreements as Total Debt minus permitted junior debt, including the deferred acquisition notes.

(4) "Debt Service Coverage" is calculated as the ratio of EBITDA to cash interest expense plus scheduled principal payments on Total Debt for the twelve months ending at the end of each fiscal quarter.

(5) Covenants in effect while the term loan and deferred acquisition notes are outstanding after which time the covenants will change to 3.5:1.0, 3.0:1.0 and 3.0:1.0 respectively.

Senior Unsecured Notes

On February 10, 2022, the Company issued $200 million aggregate principal amount of SL Notes. The SL Notes were offered pursuant to an offering memorandum and underwriting agreement entered into on February 2, 2022. The SL Notes were issued at par under a trust indenture and are general unsecured obligations of Tamarack ranking pari passu with all of the Company's existing and future senior unsecured indebtedness.

On September 22, 2022, the Company issued an additional $100 million aggregate principal amount of SL Notes also due May 10, 2027. The SL Notes were offered pursuant to a private placement memorandum and underwriting agreement, each entered into on September 12, 2022. The SL Notes were issued at a discounted principal amount (plus accrued interest from and including May 10, 2022) under the trust indenture pursuant to which Tamarack previously issued the existing SL Notes, as amended by a first supplemental indenture dated September 22, 2022.

The SL Notes were issued in accordance with the Company's Sustainability-Linked Bond Framework which sets out certain sustainability performance targets on the SL Notes ("NSPTs") including:

- NSPT 1 - Greenhouse Gas Emissions Intensity: 39% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline.
- NSPT 2 - Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025.

Failure to meet the NSPTs will result in an increase in the interest rate payable of 75 basis points for the Greenhouse Gas Emissions Intensity reduction target, and 25 basis points for the Indigenous Workforce Participation target from and including May 10, 2026.

The SL Notes are not governed by any financial covenants but contain a debt incurrence covenant that may restrict the Company's ability to raise additional senior debt beyond our existing SLL Facility and SL Notes.

The SL Notes pay interest semi-annually in arrears with the principal amount repayable at maturity. The SL Notes are redeemable at the Company's option, in whole or in part, at specified redemption prices, plus any accrued and unpaid interest up to the date of redemption, as noted in the following table:

	NSPTs Satisfied - Redemption percentages			
Redemption period	1 & 2	1	2	Neither
Prior to May 10, 2024[1]	108.250	108.250	108.250	108.250
May 10, 2024 - May 9, 2025	103.625	103.750	104.000	104.125
May 10, 2025 - May 9, 2026	101.813	101.875	102.000	102.063
May 10, 2026 - November 9, 2026	100.000	100.250	100.750	101.000
November 10, 2026 - May 9, 2027	100.000	100.125	100.375	100.500

(1) Redemption by the Company prior to May 10, 2024 of up to 40% of the aggregate principal outstanding upon issuance of an Equity Offering by the Company.

Upon the occurrence of a change of control, the SL Note holders may require the Company to repurchase such holders' SL Notes, in whole or in part, at a purchase price in cash of at least 101% of the aggregate principal amount of the SL Notes repurchased, plus accrued and unpaid interest.

On May 10, 2022, the Company made its first coupon payment of $3.5 million. The next coupon payment date is set for November 10, 2022 in the amount of approximately $10.9 million.

As at September 30, 2022 the carrying value of the SL Notes of approximately $287.4 million was net of approximately $12.6 million of discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at September 30, 2022 there was $300.0 million principal outstanding on the SL Notes.

Commitments

The following table summarizes the Company's commitments as at September 30, 2022:

($ thousands)	2022	2023	2024	2025	2026+
Senior unsecured notes[1]	–	–	–	–	300,000
Interest on senior unsecured notes[1]	5,438	21,750	21,750	21,750	29,496
Lease[2]	87	347	347	261	–
Government loan[3]	–	–	–	579	5,207
Take or pay commitments[4]	1,820	4,265	540	–	–
Processing commitments[5]	288	1,150	2,886	4,622	25,130
Gas transportation[6]	1,399	4,737	1,538	10	–
Capital commitments[7]	–	9,819	35,000	–	–
Total[8]	9,032	42,068	62,061	27,222	359,833

(1) Principal amount of the SL Notes. SL Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

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

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

(4) Pipeline commitments to deliver crude oil and or crude oil and condensate for various volumes ranging from minimums of 65 m3/d to 636 m3/d at various tariffs ranging from $9.00/m3 to $21.15/m3. These pipeline commitments are all in effect as at July 1, 2022 and last for various terms ending between December 31, 2023 and May 31, 2024. Certain of these pipeline commitments escalate at 2% per annum.

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

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

(7) Initial aggregate commitments of $255.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to March 31, 2024 of which $44.8 million is remaining to be incurred.

(8) Total commitments excludes commitments related to the Syndicated Facility of approximately $565.0 million, the Term Facility of $260.0 million (see Credit Facilities in this MD&A on page 19) and deferred acquisition notes of $300.0 million to be used in partially funding the Deltastream acquisition which closed on October 13, 2022.

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 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
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
GJ	Gigajoule
IFRS	International Financial Reporting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
NGL	natural gas liquids
WCS	Western Canadian Select
WTI	West Texas Intermediate

Non–IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures

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

(a) **Adjusted Funds Flow (Capital Management Measure)** - Adjusted funds flow is calculated by taking cash-flow from operating activities, on a periodic basis and deducting current income taxes, and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. While current income taxes will not be paid until Q1/23, management believes adjusting for estimated current income taxes in the period incurred is a better indication of the adjusted funds generated by the Company. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income per share, which results in the measure being considered a non-IFRS financial ratio. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a non-IFRS financial ratio. The calculation of the Company's adjusted funds flows is summarized starting on page 14 in the section titled "Adjusted Funds Flow and Net Income."

(b) **Net Production Expenses, Operating Netback and Operating Field Netback (Non-IFRS Financial Measures, and Non-IFRS Financial Ratios if calculated on a per boe basis)** - Management uses certain industry benchmarks, such as net production expenses, operating netback and operating field netback, to analyze financial and operating performance. Net production expenses are determined by deducting processing income primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. Under IFRS this source of funds is required to be reported as revenue. Where the Company has excess capacity at one of its facilities, it will process third party volumes as a means to reduce the cost of operating/owning the facility, and as such third party processing revenue is netted against production expenses in the MD&A. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense. 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, which results in them being considered a non-IFRS financial ratio. 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) (Capital Management Measure)** - Tamarack closely monitors our capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of our capital structure. The Company uses net debt (Credit facilities plus Senior unsecured notes plus Government loan less Notes receivable plus working capital surplus or deficiency, excluding fair value of financial instruments, decommissioning obligations, lease liabilities and the cash award incentive plan liability) 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, 2022**	December 31, 2021
Accounts payable and accrued liabilities	**$183,622**	$72,188
Current income tax liability	**53,236**	–
Cross currency swap liability	**–**	292
Cash	**(97,509)**	–
Accounts receivable	**(112,833)**	(79,904)
Prepaid expenses and deposits	**(11,443)**	(7,829)
Working capital deficiency (surplus)	**$15,073**	$(15,253)
Notes receivable	**(20,000)**	–
Credit facilities	**–**	477,437
Senior unsecured notes	**287,379**	–
Government loan	**4,310**	1,100
Net debt	**$286,762**	$463,284

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

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

($ thousands)	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Adjusted funds flow	**$177,834**	$102,486	**$530,315**	$216,179
Less: Property, plant and equipment expenditures	**96,420**	69,736	**289,916**	148,773
Government assistance	**–**	–	**(4,442)**	–
Exploration and evaluation expenditures	**2,031**	242	**47,827**	714
Free funds flow	**$79,383**	$32,508	**$197,014**	$66,692

Selected Quarterly Information								
Three months ended	**Sept. 30, 2022**	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Sep. 30, 2021	Jun. 30, 2021	Mar. 31, 2021	Dec. 31, 2020
Sales volumes								
Natural gas *(mcf/d)*	**62,428**	67,195	70,989	74,291	72,935	60,887	52,466	53,738
Oil and NGL *(bbls/d)*	**33,071**	32,578	29,503	28,002	29,100	22,268	15,194	13,093
Average boe/d *(6:1)*	**43,476**	43,777	41,335	40,384	41,256	32,416	23,938	22,049
Product prices								
Natural gas *($/mcf)*	**6.27**	7.81	5.70	5.09	3.44	2.77	3.15	2.46
Oil and NGL *($/bbl)*	**95.93**	121.17	98.61	80.55	70.40	67.47	56.91	43.22
Oil equivalent *($/boe)*	**81.98**	102.16	80.17	65.21	55.73	51.55	43.03	31.67
(000s, except per share amounts)								
Financial results								
Gross revenues	**327,910**	406,971	298,254	242,288	211,527	152,061	92,696	64,238
Cash provided by operating activities	**229,927**	214,708	132,853	118,647	100,558	40,253	38,436	23,859
Adjusted funds flow (2)	**177,834**	203,622	166,581	124,080	102,486	71,741	41,236	28,894
Per share – basic	**0.40**	0.47	0.40	0.31	0.25	0.21	0.16	0.13
Per share – diluted	**0.40**	0.46	0.39	0.30	0.25	0.21	0.16	0.13
Net income (loss)	**124,793**	143,507	26,457	140,448	20,032	230,194	(166)	(18,220)
Per share – basic	**0.28**	0.33	0.06	0.35	0.05	0.69	(0.00)	(0.08)
Per share – diluted	**0.28**	0.33	0.06	0.34	0.05	0.67	(0.00)	(0.08)
Capital expenditures	**98,451**	109,483	125,367	41,672	69,978	30,805	48,704	13,088
Acquisitions(1)	**1,365**	112,175	224,270	22,593	52,004	539,506	147,187	94,684
Dispositions(1)	**(59,498)**	(15,482)	–	(74)	(8,140)	(32,283)	(13,884)	(15,525)
Total assets	**2,839,146**	2,829,984	2,648,093	2,328,153	2,230,382	2,180,303	1,199,743	1,027,600
Net debt(2)	**286,762**	470,563	556,374	463,284	519,708	505,992	286,175	219,311
Credit facilities (cash)	**(97,509)**	324,761	325,899	477,437	520,961	520,012	270,810	210,857
Senior notes payable	**287,379**	195,086	195,096	–	–	–	–	–
Decommissioning obligations	**237,813**	238,768	270,458	284,472	265,929	264,791	242,692	245,437

(1) Includes cash and non-cash consideration.

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

Significant factors and trends that have impacted the Company's results during the above quarterly 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 July 21, 2022, Tamarack closed the disposition of non-Core Viking oil CGU assets for net consideration of approximately $59.5 million (inclusive of a $20.0 million promissory note at 12% interest maturing on July 21, 2025).
- On June 10, 2022, Tamarack closed the acquisition of Southern Clearwater area properties. The assets include approximately 2,100 boe/d of oil weighted assets, along with adding 34,560 net acres in the Southern Clearwater oil play of Alberta for a total purchase price of approximately $108.1 million.

- On February 15, 2022, Tamarack closed the acquisition of Southern Clearwater area properties. The assets include approximately 3,500 boe/d of oil weighted assets, along with adding 153.7 net sections in the Southern Clearwater oil play of Alberta for a total purchase price of approximately $228.3 million.
- On June 1, 2021, Tamarack closed the acquisition of Charlie Lake area properties in the Grande Prairie field of Alberta. The assets include approximately 11,800 boe/d of oil weighted assets, along with adding 349.7 net sections in the Charlie Lake oil play of Alberta for a total purchase price of approximately $538.4 million.
- On March 25, 2021, Tamarack closed two separate agreements to acquire assets in the Northern Clearwater (Nipisi) and Eyehill (Provost) areas in Alberta. The assets include approximately 2,800 boe/d of low decline (~16%) oil weighted assets under waterflood, along with adding approximately 38,400 net acres in the Northern Clearwater oil play of Alberta for a total purchase price of approximately $147.2 million.
- On December 21, 2020, the Company completed two acquisitions of certain oil properties located in the Northern (Nipisi) and Southern (Jarvie) Clearwater areas in Alberta. The assets include approximately 2,000 bbls/d of crude oil production in the Northern and Southern Clearwater oil plays supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.
- The Company recorded an impairment reversal in Q4/21 in the amount of $90.0 million on the Viking oil CGU, Cardium oil CGU and Penny oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed $52.3 million, the Cardium oil CGU reversed $14.3 million and the Penny oil CGU reversed $23.4 million.
- The Company recorded an impairment reversal in Q2/21 in the amount of $300.0 million on the Viking oil CGU and Cardium oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed $160.0 million and the Cardium oil CGU reversed $140.0 million.
- The Company recorded an impairment charge in Q4/20 in the amount of $18.0 million on our Penny oil CGU due to a reduction in the current quantities of recoverable proved and probable oil and natural gas reserves.

Critical Accounting Estimates

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

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

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

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

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

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

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

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

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

(e) **Business combinations** – The application of the Company's accounting policy for business combinations requires management to make certain judgments on a case-by-case basis as to the determination of the accounting method of an acquisition to determine if the assets acquired meet the definition of a business combination or an asset acquisition. In a business combination, management makes estimates of the acquisition-date fair value of assets acquired and liabilities assumed which includes assessing the estimated fair value of oil and natural gas interests (included in property, plant and equipment). The determination of the acquisition-date fair value of oil and natural gas interests involves significant estimates, including the estimate of proved and probable oil and natural gas reserves and the related cash flows and the discount rates. The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs and forecasted future development costs. The estimates of proved and probable oil and natural gas reserves and the related cash flows are prepared by the Company's external independent qualified reserves evaluator or internal reserves evaluator.

Disclosure Controls and Internal Controls over Financial Reporting

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

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

No material weaknesses in or changes to the Company's DCP and its ICFR were identified during the period ended September 30, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls 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, 2021.

(a) Continued Volatility in Commodity and Petroleum Products Prices

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

Since the second half of 2021, the crude oil market has responded positively as the OPEC+ alliance unwinds cuts as part of the output recovery scheme in conjunction with a gradual global economic recovery from the COVID-19 pandemic; however, the potential for volatility in crude oil demand and supply remains. Recent surges of COVID-19 cases in China have resulted in strict policies and lockdowns in major Chinese cities intended to contain the spread of COVID-19. These policies have negatively impacted financial markets on a global scale and continue to put further strain on global supply chains.

While the recovery in oil demand as a result of the easing of COVID-19 restrictions, combined with a prudent supply policy implemented by the OPEC+ alliance, has resulted in crude oil prices recovering to pre-pandemic levels, the extent and duration of this recovery remains uncertain. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada. The overall impact of these market conditions and the potential for decreased confidence in the Canadian crude oil and natural gas industry could materially and adversely affect Tamarack's business, prospects, financial condition, results of operations and cash flows.

To date in 2022, global crude oil prices have risen to the highest levels since 2014 due to tight supply and a resurgence in demand, furthered by escalating military tensions in Eastern Europe following Russia's invasion of Ukraine. Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tensions in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine, as well as other major Ukrainian cities. Ongoing military tensions between Russia and Ukraine have the potential to threaten the supply of oil and gas from the region. The long-term impacts of the tension between these nations remains uncertain.

The overall result of these events and conditions could lead to a prolonged period of volatile prices for oil and other petroleum products. Price volatility could result in reduced utilization and/or the suspension of operations at certain of the Company's facilities, buyers of the Company's products declaring force majeure and disruptions of pipeline and other transportation systems for the Company's products, which would further negatively impact Tamarack's production, and could adversely impact Tamarack's business, financial condition and results of operations.

(b) Inflation Risk

The general rate of inflation in Canada and many other countries saw a significant increase during 2021 and continuing throughout the first nine months of 2022, with some regions experiencing multi-decade highs. These increases reflect imbalances between supply and demand recoveries from the pandemic. The underlying factors include, but are not limited to, global supply chain disruptions, shipping bottlenecks, labor market constraints, geopolitical instability, and side effects from monetary and fiscal expansions. The global economic recovery remains uncertain. Prices for services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. Tamarack closely monitors market trends and works to mitigate cost impacts in all price environments through its economies of scale in procurement, efficient project management practices, and general productivity improvements.

The global economic recovery and rising inflationary trends are widely expected to result in rising interest rates. The ongoing invasion of Ukraine is another factor that could influence inflation or other parts of the Canadian and global economy. Since March 2, 2022, the Bank of Canada has begun to raise its benchmark interest rates for the first time since 2018. Further interest rate increases are anticipated over the next twelve months.

(c) Environmental and Climate Change Risk

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

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

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

Financial Risks

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

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

Operational Risks

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

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

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

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

Regulatory Risks

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

The ISSB is expected to develop globally consistent, comparable and reliable standards for disclosing and reporting ESG and climate-related metrics. On March 31, 2022, the ISSB issued exposure drafts *IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information"* and *IFRS S2 "Climate-related Disclosures"* and the exposure drafts are open for comment until July 29, 2022. IFRS S1 *"sets out the overall requirements for disclosing sustainability-related financial information in order to provide primary users with a complete set of sustainability-related financial disclosures."* IFRS S2 *"sets out the requirements for identifying, measuring and disclosing climate-related risks and opportunities as part of an entity's general purpose financial reporting."* The exposure drafts do not currently disclose an effective date for the application of any future sustainability standards and accordingly, the Company is not able at this time to determine the impact on future financial statements or the cost of adopting any future standards that may result from these exposure drafts. In addition, the Canadian Securities Administrators have issued a proposed NI 51-107 Disclosure of Climate-related Matters. The cost to implement and comply with these standards, and others, that may be developed or evolved over time, has not yet been quantified.

Forward-Looking Statements

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

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

- the intentions of management and the Company;
- the Company's commitment to maintaining financial flexibility and liquidity;
- the Company's business strategy, objectives, strength and focus, including with respect to acquisitions;
- the effects of the Company's acquisitions on the Company's strategy, land holdings and profitability, including, but not limited to, the Anegada Oil Corp. acquisition, the Crestwynd Exploration Ltd. acquisition, the Rolling Hills Energy Ltd. acquisition, the Deltastream Energy Corporation acquisition and the various acquisitions of Northern and Southern Clearwater and Eyehill assets;
- the implementation of the Nipisi gas conservation project and the objectives thereof;
- the COVID-19 pandemic, the Company's and governmental authorities' current and planned responses thereto and the impact thereof on, without limitation, the Company in particular, including the Company's capital expenditure plans, and the oil and gas industry in general;
- uncertainty regarding the full impact of COVID-19 on global economies and oil demand and commodity prices, including the effects of recent outbreaks of COVID-19 in China;
- the timing of full economic recovery related to the COVID-19 pandemic;
- the impacts on the Company of the military conflict between Russia and Ukraine;
- applications and grants under the Canada Emergency Wage Subsidy ("**CEWS**"), Alberta Site Rehabilitation Program ("**SRP**"), Saskatchewan Accelerated Site Closure Program ("**ASCP**") programs, the Federal Emissions Reduction Fund ("**ERF**"), the Alberta Methane Technology Information Program ("**MTIP**"), including estimates of expected funding, and repayment timing thereof, as applicable;
- the Company's commitment to advancing ESG practices, managing greenhouse gas emissions and to continued Indigenous and community partnerships in the areas where it operates;
- the potential impact of ESG disclosure and reporting policies and standards imposed by the ISSB and proposed NI 51-107;
- expectations regarding the estimated recoverable amount of the Company's oil and gas properties, royalty rates as a percentage of revenue, and committed capital spending to develop the GORR lands and timing thereof;
- expectations relating to future realized commodity prices, volatile commodity prices, royalty rates and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing;
- the Company's diversification strategy, including the Company's third-party gas sales contracts, and the effects thereof on risk mitigation, price exposure and realized price improvements;
- the Company's financial and physical hedging program, including the use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates, and interest rates, and the effects thereof on cash flow risk and commodity pricing upside;
- any purchases under the NCIB program;

- the Company's plans in respect of returns of capital, including base dividend and enhanced return programs;
- expectations regarding the Company's ability to satisfy its 2022 development capital program and dividend payments for the 2022 fiscal year through available credit facilities combined with anticipated adjusted funds flow;
- the availability, size, terms, use and renewal of the Company's SLL Facility, including the various lending vehicles used by the Company from time to time, and the terms thereof;
- the Company's SL Notes, and the Company's ability to meet its obligations and commitments thereunder;
- expectations relating to cash tax, tax pools, and deferred tax assets, including in respect of deferred income tax;
- future RSU, PSU, RIA, and PIA settlements;
- the Company's head office sublease, as amended or extended, and the terms thereof;
- contractual obligations and commitments;
- estimates used to calculate decommissioning obligations and depletion of PP&E;
- expectations regarding the merits and the outcome of ongoing litigation; and
- the Company's expectations regarding inflation and interest rates.

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

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production expenses and transportation expenses;
- estimated proved and probable oil and natural gas reserves;
- the effects of heavy volume apportionment and fluctuating diluent costs on the heavy oil market in Alberta;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the acquisitions and the related drilling programs;
- the ability to explore and realize benefits from exposure to diversified gas markets;
- drilling results, including field production rates and decline rates;
- the performance of the waterflood projects;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms;
- the continuation of the current tax, royalty and regulatory regime;
- the volatility in commodity prices and oil price differentials and the resulting effect on Tamarack's revenue, cash provided by operating activities, adjusted funds flows and earnings;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand;
- the ability to adjust capital spending relative to commodity prices and use financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;

- the ability to maintain financial flexibility;
- Tamarack's ability to execute its plans in response to the COVID-19 pandemic; and
- the impact of inflation on costs and interest rates.

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

- the material uncertainties and risks described under the headings "Unit Cost Calculation", "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management 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 "Message to Shareholders", "Q3 2022 Operational and Financial Highlights", "Climate Change and Sustainability", "Production", "Petroleum and Natural Gas Sales", "Risk Management", "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 of Property, Plant and Equipment", "Income Taxes", "Adjusted Funds Flow and Net Income", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Acquisitions and Dispositions", "Share Capital", "Liquidity and Capital Resources", "Credit Facilities", "Senior Unsecured Notes", "Commitments", "Contingency" and "Selected Quarterly Information";
- the COVID-19 pandemic and the impact on the Company's business, financial condition and results of operations;
- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production and including continued weakness and volatility in commodity prices and petroleum product prices;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating proved and probable oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to markets for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- credit worthiness of counterparties to commodity, foreign exchange and interest rate contracts;
- increased borrowing costs due to increased lending rates from prime rate increase, negative changes to financial metrics evaluated under SLL Facility and SL Notes sustainability performance targets and/or decreased ESG performance as determined by a third-party rating agency;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production costs, transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources;
- changes in tax, royalty and environmental legislation and any government policy;

- any legal proceedings, the results thereof and the impact on the Company's business, financial condition and results of operations;
- changes in the political landscape, both domestically and abroad; and
- increased operating and capital costs due to inflationary pressures (actual and anticipated).

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also, to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2021, which may be accessed on Tamarack's SEDAR profile www.sedar.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, production, adjusted funds flow, free funds flow, net debt, net debt to annualized adjusted funds flow, corporate decline rates, royalty rates and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non–IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures", and should not be used for purposes other than those for which it is disclosed herein. Tamarack and its management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, Tamarack's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future activities or results.

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited) (thousands)

	September 30, 2022	December 31, 2021
Assets		
Current assets:		
Cash	**$97,509**	$ –
Accounts receivable (note 5)	**112,833**	79,904
Prepaid expenses and deposits	**11,443**	7,829
Fair value of financial instruments (note 3)	**7,860**	–
	229,645	87,733
Notes receivable (note 8)	**20,000**	–
Fair value of financial instruments (note 3)	**1,068**	77
Property, plant and equipment (note 6 and 8)	**2,541,830**	2,236,535
Exploration and evaluation assets (note 7)	**46,603**	3,808
	$2,839,146	$2,328,153
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$183,622**	$72,188
Other liabilities (note 14 and 19)	**4,738**	–
Lease liabilities (note 10)	**4,038**	3,600
Decommissioning obligations (note 9)	**11,200**	5,298
Cross-currency swap	**–**	292
Current income tax liability	**53,236**	–
Fair value of financial instruments (note 3)	**4,648**	13,146
	261,482	94,524
Credit facilities (note 12)	**–**	477,437
Senior unsecured notes (note 13)	**287,379**	–
Other liabilities (note 14 and 19)	**8,074**	1,100
Lease liabilities (note 10)	**6,361**	6,932
Fair value of financial instruments (note 3)	**175**	17
Decommissioning obligations (note 9)	**226,613**	279,174
Deferred tax liability	**245,837**	208,344
	1,035,921	1,067,528
Shareholders' equity:		
Share capital (note 16)	**1,552,389**	1,242,392
Treasury shares (note 16)	**(2,150)**	(3,336)
Contributed surplus	**24,964**	48,311
Retained earnings (deficit)	**228,022**	(26,742)
	1,803,225	1,260,625
Subsequent events (notes 3, 8, 12 and 16)		
Commitments (note 20)		
Contingency (note 21)		
	$2,839,146	$2,328,153

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income and Comprehensive Income
For the three and nine months ended September 30, 2022 and 2021
(unaudited) (thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Revenue:				
Oil and natural gas (note 5)	**$327,910**	$211,527	**$1,033,135**	$456,284
Processing and other income (note 5)	**1,867**	738	**2,732**	1,583
Royalties	**(56,256)**	(34,045)	**(192,990)**	(66,849)
Net revenue	**273,521**	178,220	**842,877**	391,018
Financial instrument contracts:				
Realized loss on financial instruments (note 3)	**(11,615)**	(23,560)	**(63,916)**	(50,058)
Unrealized gain (loss) on financial instruments (note 3)	**47,820**	(2,153)	**32,064**	(32,979)
Net revenue and gains (losses) on financial instruments	**309,726**	152,507	**811,025**	307,981
Expenses:				
Production	**42,347**	33,437	**122,255**	83,037
Transportation	**11,511**	7,265	**29,143**	14,230
General and administration	**5,811**	5,000	**20,268**	13,020
Transaction costs	**–**	1,125	**–**	8,110
Stock-based compensation (note 18)	**409**	1,158	**3,745**	3,791
Finance (note 15)	**10,419**	7,808	**30,559**	17,984
Depletion, depreciation and amortization (note 6 and 7)	**78,394**	72,659	**225,235**	150,288
Gain on disposition of property, plant and equipment (note 8)	**(2,691)**	(892)	**(4,943)**	(8,735)
Site rehabilitation program grant (note 9 and 19)	**(1,494)**	(743)	**(2,198)**	(2,144)
Reversal of impairment of property, plant and equipment (note 6)	**–**	–	**–**	(300,000)
	144,706	126,817	**424,064**	(20,419)
Income before taxes	**165,020**	25,690	**386,961**	328,400
Taxes:				
Current income tax expense	**(19,894)**	–	**(53,236)**	–
Deferred income tax expense	**(20,333)**	(5,658)	**(38,968)**	(78,340)
	(40,227)	(5,658)	**(92,204)**	(78,340)
Net income and comprehensive income	**$124,793**	$20,032	**$294,757**	$250,060
Net income per share (note 17):				
Basic	**$ 0.28**	$ 0.05	**$ 0.68**	$ 0.74
Diluted	**$ 0.28**	$ 0.05	**$ 0.68**	$ 0.73

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	Retained earnings (deficit)	Total Shareholders ' equity
Balance at January 1, 2021	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
Balance at January 1, 2022	406,938	$1,242,392	$(3,336)	$48,311	$(26,742)	$1,260,625
Issue of common shares	73,909	331,955	–	–	–	331,955
Purchase of common shares for cancellation	(4,363)	(14,375)	–	–	(4,223)	(18,598)
Purchase of common shares for Option, RSU and PSU exercise	(3,528)	–	(17,286)	–	–	(17,286)
Option, RSU and PSU exercise	3,446	–	14,703	(14,703)	–	–
Change to liability SBC	–	–	–	(14,685)	–	(14,685)
Option exercise proceeds	–	–	1,691	–	–	1,691
Return of common shares to treasury	–	(2,646)	2,078	568	–	–
Share issue costs, net of tax of $1,475	–	(4,937)	–	–	–	(4,937)
Stock-based compensation	–	–	–	5,473	–	5,473
Dividends	–	–	–	–	(35,770)	(35,770)
Net income	–	–	–	–	294,757	294,757
Balance at September 30, 2022	476,402	$1,552,389	$(2,150)	$24,964	$228,022	$1,803,225

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, 2022 and 2021
(unaudited) (thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Cash provided by (used in):				
Operating:				
Net income	**$124,793**	$20,032	**$294,757**	$250,060
Depletion, depreciation and amortization (note 6 and 7)	**78,394**	72,659	**225,235**	150,288
Stock-based compensation (note 18)	**409**	1,158	**3,745**	3,791
Stock-based compensation paid (note 18)	**(196)**	–	**(6,651)**	–
Gain on disposition of property, plant and equipment (note 8)	**(2,691)**	(892)	**(4,943)**	(8,735)
Site rehabilitation program grant (note 9 and 19)	**(1,494)**	(743)	**(2,198)**	(2,144)
Finance (note 15)	**10,419**	7,808	**30,559**	17,984
Interest paid (note 11)	**(4,313)**	(6,472)	**(17,093)**	(14,494)
Unrealized loss (gain) on financial instruments (note 3)	**(47,820)**	2,153	**(32,064)**	32,979
Impairment reversal of property, plant and equipment (note 6)	**–**	–	**–**	(300,000)
Income tax expense	**40,227**	5,658	**92,204**	78,340
Decommissioning expenditures (note 9)	**(2,951)**	(1,046)	**(5,429)**	(2,892)
Changes in non-cash working capital (note 11)	**35,150**	243	**(634)**	(25,930)
Cash provided by operating activities	**229,927**	100,558	**577,488**	179,247
Financing:				
Change in credit facilities (note 12)	**(314,724)**	6,982	**(479,243)**	308,678
Issuance of senior unsecured notes, net (note 13)	**92,024**	–	**286,654**	–
Repayment of acquired debt	**–**	–	**–**	(37,734)
Proceeds from issuance of shares, net (note 16)	**137,341**	–	**137,341**	71,227
Purchase of common shares for cancellation (note 16)	**(12,782)**	–	**(18,598)**	–
Purchase of common shares for Option, RSU and PSU exercises (note 16 and 18)	**–**	(228)	**(17,286)**	(4,941)
Proceeds from option exercises (note 18)	**–**	–	**1,691**	–
Repayment of lease liabilities (note 10)	**(964)**	(903)	**(2,817)**	(2,254)
Dividends (note 16)	**(8,787)**	–	**(31,001)**	–
Changes in other liability (note 14 and 19)	**226**	–	**2,928**	–
Changes in non-cash working capital (note 11)	**(4,417)**	–	**1,120**	(1,005)
Cash provided by (used in) financing activities	**(112,083)**	5,851	**(119,211)**	333,971
Investing:				
Property, plant and equipment additions (note 6)	**(96,420)**	(69,736)	**(289,916)**	(148,773)
Government assistance (note 14 and 19)	**–**	–	**4,442**	–
Exploration and evaluation additions (note 7)	**(2,031)**	(242)	**(47,827)**	(714)
Acquisitions (note 8)	**(1,365)**	(42,917)	**(149,389)**	(439,183)
Proceeds from disposal of property, plant and equipment (note 8)	**39,498**	**–**	**54,980**	46,167
Changes in non-cash working capital (note 11)	**39,983**	6,486	**66,942**	29,285
Cash used in investing activities	**(20,335)**	(106,409)	**(360,768)**	(513,218)
Change in cash	**97,509**	–	**97,509**	–
Cash, beginning of period	**–**	–	**–**	–
Cash, end of period	**$97,509**	$ –	**$97,509**	$ –

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 consolidated financial statements of Tamarack consist of the Company and its subsidiary. The Company has the following wholly owned subsidiary, which is incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. 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, 2021, except as noted below. 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, 2021. Certain prior period balances were reclassified to conform to current period presentation.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on October 27, 2022.

(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, 2021. Since the World Health Organization declared the novel coronavirus (COVID-19) outbreak a global pandemic in March 2020, there has been significant oil supply and demand volatility. As we entered 2022, most countries started to reopen their economies positively impacting both demand and benchmark commodity pricing. In addition, the Russia-Ukraine conflict has raised global concerns over oil and natural gas supply and significantly increased benchmark prices and inflationary pressures on governments, businesses, and communities. Natural gas demand and pricing has continued to remain strong in 2022. Improved benchmark pricing has positively impacted the oil and gas industry and Tamarack, but the potential for volatility remains. Management has incorporated the anticipated impacts of COVID-19 and the resulting economic recovery, as well as the impacts from the Russia-Ukraine conflict in its estimates and assumptions at period end and continues to monitor current commodity prices, currency exchange rates and industry activity levels.

(c) Climate change:

The Company has considered the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources. The impacts of climate change and the advancement of the transition to alternative energy sources is a source of uncertainty and impacts on key estimates and their assumption made by management affecting the measurement of balances and transaction in these condensed consolidated interim financial statements. The impact of uncertainties regarding climate change and the effect they may have on management's estimates may impact on property, plant and equipment, depletion, impairment and impairment reversal, reserves estimates, decommissioning obligations, credit facilities and share capital.

(d) Significant accounting policies:

The accounting policies, critical accounting judgments and significant estimates used in the preparation of the December 31, 2021 annual consolidated financial statements have been applied in the preparation of these condensed consolidated interim financial statements, except for the change noted below:

Effective March 9, 2022, Performance Share Units ("PSUs") and Restricted Share Units ("RSUs") ("PRSUs") granted prior to that date for the Company's "Insiders" (Insiders as defined in securities legislation, excluding Directors of the Company) upon vesting will be settled in cash. For all other non-insiders participating in the PRSU plan, the PRSU awards will continue to be equity-settled. The value of the share awards to Insiders PRSUs, granted prior to March 9, 2022, were reclassified from Contributed Surplus to Other Liabilities on the Condensed Consolidated Interim Balance Sheet. The fair value of PRSUs that are accounted for as cash-settled transactions are subsequently adjusted to the underlying Common Share price at each period end.

On March 9, 2022, the Company's Board of Directors approved the implementation of a new Cash Award Incentive Plan ("CAI Plan"), which will be used for future Restricted Incentive Award (RIA) and Performance Incentive Award (PIA) grants that will be cash-settled. Both insiders and non-insiders are eligible for grants of awards under the new Cash Award Incentive Plan.

3. Financial Instruments and Risk Management:

(a) Financial instruments:

The Company's financial assets and liabilities are comprised of Cash, Accounts receivable, Prepaid expenses and deposits, Notes receivable, Accounts payables and accrued liabilities, Current income tax liabilities, Fair value of financial instruments, Cross-currency swap, Other liabilities (includes Cash award incentive plan liability and Government loan liability), Credit facilities and Senior unsecured notes. The carrying value of Cash, Notes receivable, Credit facilities and Senior unsecured notes approximates its fair value as it bears interest at market rates. Except for the Fair value of financial instruments, Cross-currency swap and the Cash award incentive plan liability, which are recorded at fair value through profit or loss, carrying values reflect the current fair value of the Company's financial instruments due to their short-term maturities.

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods outlined below. The Company's fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(b) Financial derivatives:

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 investment grade banking institutions or large purchasers of commodities. 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 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 costless collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. Derivatives are recorded on the balance sheet at fair value with the change in fair value being recognized as an unrealized gain or loss in profit or loss. Cross-currency swaps are recorded on the balance sheet at fair value with the change in fair value being recognized as a finance expense.

At September 30, 2022, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

West Texas Intermediate and Differential Crude Oil Derivatives

	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023
WTI Put					
Volume (bbls/d)	**4,250**	**6,000**	**2,000**	**-**	**-**
Average Put/Premium (USD/bbl)	56.43 3.18	55.00 2.99	55.00 2.90	- -	- -
WTI 2-way Collar					
Volume (bbls/d)	**12,000**	**11,000**	**11,500**	**8,500**	**1,500**
Average Put/Call/Premium (USD/bbl)	57.48 106.18 1.95	66.59 108.44 2.27	67.63 110.89 2.57	67.06 102.67 2.88	68.00 92.12 3.00
Volume (bbls/d)	**800**	**-**	**-**	**-**	**-**
Average Put/Call/Premium (CAD/bbl)	80.00 100.83 -	- - -	- - -	- - -	- - -
WTI 3-way Collar (Reverse)					
Volume (bbls/d)	**750**	**-**	**-**	**-**	**-**
Average Put/Call/Sold Put/Premium (USD/bbl)	55 70 74 2	- - - -	- - - -	- - - -	- - - -
WTI Fixed Price					
Volume (bbls/d)	**500**	**-**	**-**	**-**	**-**
Average Fixed Price (USD/bbl)	87.25	-	-	-	-
Volume (bbls/d)	**500**	**-**	**-**	**-**	**-**
Average Fixed Price (CAD/bbl)	88.25	-	-	-	-
Mixed Sweet Blend Differential (MSW)					
Volume (bbls/d)	**9,000**	**-**	**-**	**-**	**-**
Average Fixed Price (USD/bbl)	(3.46)	-	-	-	-
Western Canadian Select Differential (WCS)					
Volume (bbls/d)	**6,500**	**-**	**-**	**-**	**-**
Average Fixed Price (USD/bbl)	(12.12)	-	-	-	-

Natural Gas Derivatives

	Summer 22[1]		Nov-Dec 22		Winter 22-23[2]		Summer 23[1]	
AECO 5A Swap								
Volume (GJ/d)	**31,500**		**1,500**		**10,000**		**-**	
Average Fixed Price (CAD/GJ)	2.46		3.17		3.85		-	
AECO - NYMEX Basis								
Volume (mmbtu/d)	**-**		**-**		**-**		**15,000**	
Average Fixed Price (USD/mmbtu)	-		-		-		1.88	
AECO 7A Collar								
Volume (GJ/d)	**-**		**-**		**20,000**		**-**	
Average Put/Call (CAD/GJ)	-	-	-	-	3.65	6.14	-	-
NYMEX Collar								
Volume (mmbtu/d)	**-**		**-**		**-**		**15,000**	
Average Put/Call (USD/mmbtu)	-	-	-	-	-	-	4.58	7.24

(1) Summer runs from April 1 to October 31 of the given year.
(2) Winter runs from November 1 to March 31 of the given year.

Foreign Exchange Derivatives

	Q4 2022			Q1 2023			Q2 2023			Q3 2023			Q4 2023		
CAD/USD Put															
Amount (USD/month)	**$13,000,000**			**-**			**-**			**-**			**-**		
Average Put/Premium (CAD/USD)	1.3314	0.0101		-	-		-	-		-	-		-	-	
CAD/USD Collar															
Amount (USD/month)	**$1,000,000**			**$1,000,000**			**$1,000,000**			**$1,000,000**			**$1,000,000**		
Average Put/Call (CAD/USD)	1.2500	1.3420		1.2500	1.3420		1.2500	1.3420		1.2500	1.3420		1.2500	1.3420	
CAD/USD Variable Rate Collar															
Amount (USD/month)	**$10,000,000**			**-**			**-**			**-**			**-**		
Average Put/Call (CAD/USD)	1.34	1.44	1.37	-	-	-	-	-	-	-	-	-	-	-	-
CAD/USD Swap															
Amount (USD/month)	**$9,000,000**			**-**			**-**			**-**			**-**		
Average Fixed Price (CAD/USD)	1.3546			-			-			-			-		
CAD/USD Target Average Rate Forward[1]															
Amount (USD/month)	**$500,000**			**-**			**-**			**-**			**-**		
Average Fixed Price (CAD/USD)	1.2640			-			-			-			-		

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

Interest Rate Derivatives

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

At September 30, 2022, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net asset value of $4,105 (December 31, 2021 - $13,086 net liability) recorded on the balance sheet. The Company had an unrealized gain of $47,820 and a realized loss of $11,615 recorded in earnings for the three months ended September 30, 2022 (September 30, 2021 - $2,153 unrealized loss and $23,560 realized loss). The Company had an unrealized gain of $32,064 and a realized loss of $63,916 recorded in earnings for the nine months ended September 30, 2022 (September 30, 2021 - $32,979 unrealized loss and $50,058 realized loss).

Subsequent to September 30, 2022, the Company has entered into the financial contracts noted in the tables below.

West Texas Intermediate and Differential Crude Oil Derivatives

	Nov/Dec 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023
WTI 2-way Collar					
Volume (bbls/d)	**-**	**10,000**	**14,500**	**12,750**	**5,500**
Average Put/Call/Premium (USD/bbl)	- - -	77.50 94.25 3.00	70.50 98.47 3.00	68.00 95.27 3.00	68.00 89.75 3.00
WTI Fixed Price					
Volume (bbls/d)	**12,500**	**1,000**	**-**	**-**	**-**
Average Fixed Price (USD/bbl)	84.85	80.89	-	-	-

Subsequent to September 30, 2022, the Company has assumed the financial contracts noted in the tables below as part of the Deltastream acquisition.

West Texas Intermediate and Differential Crude Oil Derivatives

	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023
WTI 2-way Collar					
Volume (bbls/d)	**1,775**	**1,050**	**1,050**	**850**	**850**
Average Put/Call/Premium (CAD/bbl)	79.03 103.57 -	82.90 110.94 -	82.90 110.94 -	80.44 108.64 -	80.44 108.64 -
WTI 3-way Collar					
Volume (bbls/d)	**500**	**-**	**-**	**-**	**-**
Average Put/Call/Sold Call/Premium (CAD/bbl)	44 57 76 -	- - - -	- - - -	- - - -	- - - -
WTI Fixed Price					
Volume (bbls/d)	**1,925**	**300**	**300**	**200**	**200**
Average Fixed Price (CAD/bbl)	87.99	94.23	94.23	91.75	91.75
Western Canadian Select Differential (WCS)					
Volume (bbls/d)	**3,400**	**1,000**	**1,000**	**700**	**700**
Average Fixed Price (CAD/bbl)	(17.80)	(18.66)	(18.66)	(19.29)	(19.29)

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, 2022, the Company held no physical commodity contracts. Subsequent to September 30, 2022, the Company has not entered into any physical commodity contracts.

Assets and liabilities related to risk management contracts 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	**September 30, 2022**	December 31, 2021
Risk management contracts		
Current asset	**$7,860**	$–
Long-term asset	**1,068**	77
Current liability	**(4,648)**	(13,146)
Long-term liability	**(175)**	(17)
Balance, end of the period	**$4,105**	$(13,086)

4. Capital management:

The Company's policy is to maintain a strong capital base to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include Shareholders' equity, Notes receivable, Credit facilities, Senior unsecured notes, Government loan and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending to manage current and projected debt levels.

(a) Adjusted funds flow:

Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment. Adjusted funds flow is calculated by taking cash flow from operating activities, on a periodic basis and deducting current income taxes, and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs.

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Cash flow from operating activities	**$229,927**	$100,558	**$577,488**	$179,247
Current income taxes	**(19,894)**	–	**(53,236)**	–
Decommissioning expenditures	**2,951**	1,046	**5,429**	2,892
Transaction costs	**–**	1,125	**–**	8,110
Changes in non-cash working capital	**(35,150)**	(243)	**634**	25,930
Adjusted funds flow	**$177,834**	$102,486	**$530,315**	$216,179

(b) Free funds flow:

Free funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, calculated as property, plant and equipment additions (net of government assistance) plus exploration and evaluation additions included in the Condensed Consolidated Interim Statements of Cash Flows.

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Adjusted funds flow	**$177,834**	$102,486	**$530,315**	$216,179
Less: Property, plant and equipment expenditures	**96,420**	69,736	**289,916**	148,773
Government assistance	**–**	–	**(4,442)**	–
Exploration and evaluation expenditures	**2,031**	242	**47,827**	714
Free funds flow	**$79,383**	$32,508	**$197,014**	$66,692

(c) Net debt to annualized adjusted funds flow:

The Company monitors capital based on the ratio of net debt to annualized adjusted funds flow. This ratio is calculated as net debt, defined as working capital deficiency (surplus) plus Credit facilities plus Senior unsecured notes plus Government loan liability, less Notes receivable, divided by adjusted funds flow for the most recent calendar quarter and then annualized. Working capital deficiency (surplus) is calculated as Accounts payable and accrued liabilities plus Cross-currency swap liability plus Current income tax liability minus Cash minus Accounts receivable minus Prepaid expenses and deposits minus Cross-currency swap asset.

The Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at September 30, 2022, the Company's ratio of net debt to annualized third quarter adjusted funds flow was 0.4 to 1 (December 31, 2021 – 0.9 to 1). The Company believes that available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's 2022 development capital program and dividend payments for the 2022 fiscal year.

	September 30, 2022	December 31, 2021
Working capital deficiency (surplus)	**$15,073**	$(15,253)
Notes receivable	**(20,000)**	–
Credit facilities	**–**	477,437
Senior unsecured notes	**287,379**	–
Government loan	**4,310**	1,100
Net debt	**$286,762**	$463,284
Quarterly adjusted funds flow	**$177,834**	$124,080
Annualized factor	**4**	4
Annualized adjusted funds flow	**$711,336**	$496,320
Net debt to annualized adjusted funds flow	**0.4x**	0.9x

September 30, 2022 Net debt is lower as compared to prior periods primarily due to the generation of funds flow to pay down the SLL facility, cash proceeds from the Viking oil CGU disposition, and net proceeds from issuing common shares to be used to partially fund the Deltastream acquisition which closed on October 13, 2022. Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements.

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 northwestern 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.

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

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Light oil	**$167,023**	$141,288	**$569,281**	$299,164
Heavy oil	**108,308**	34,005	**285,804**	71,651
Natural gas	**36,028**	23,050	**120,197**	53,271
Natural gas liquids	**16,551**	13,184	**57,853**	32,198
Oil and natural gas revenue	**$327,910**	$211,527	**$1,033,135**	$456,284
Processing revenue	**1,394**	738	**2,259**	1,583
Total revenue	**$329,304**	$212,265	**$1,035,394**	$457,867

Included in accounts receivable at September 30, 2022 was $101.1 million (December 31, 2021 - $71.7 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, 2022, the Company did not have any contracts for the sale of its future production beyond one year in term.

6. Property, plant and equipment:

	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at December 31, 2020	$2,337,252	$2,611	$2,339,863
Right-of-use assets (note 10)	–	1,914	1,914
Acquisitions	905,780	73	905,853
Capital additions [(1)]	186,547	1,017	187,564
Decommissioning costs	23,573	–	23,573
Stock-based compensation	3,588	–	3,588
Transfer from exploration and evaluation assets (note 7)	532	–	532
Disposals	(65,733)	–	(65,733)
Balance at December 31, 2021	3,391,539	5,615	3,397,154
Right-of-use assets (note 10)	1,283	1,401	2,684
Acquisitions (note 8)	356,916	–	356,916
Capital additions [(1)]	284,811	663	285,474
Decommissioning costs	(35,824)	–	(35,824)
Stock-based compensation	2,196	–	2,196
Transfer from exploration and evaluation assets (note 7)	3,148	–	3,148
Disposals (note 8)	(136,030)	–	(136,030)
Balance at September 30, 2022	$3,868,039	$7,679	$3,875,718
Accumulated depletion, depreciation and impairment:			
Balance at December 31, 2020	$1,394,856	$1,577	$1,396,433
Depletion and depreciation	211,093	529	211,622
Disposals	(57,436)	–	(57,436)
Impairment reversal	(390,000)	–	(390,000)
Balance at December 31, 2021	1,158,513	2,106	1,160,619
Depletion and depreciation	222,168	1,183	223,351
Disposals (note 8)	(50,082)	–	(50,082)
Balance at September 30, 2022	$1,330,599	$3,289	$1,333,888

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2021	$2,233,026	$3,509	$2,236,535
At September 30, 2022	$2,536,651	$5,179	$2,541,830

(1) Includes government assistance of $1.5 million and $5.2 million, respectively, as at September 30, 2022 and December 31, 2021.

(a) Security:

At September 30, 2022 and December 31, 2021, all of the Company's properties were pledged as security for the credit facilities (note 12).

(b) Depletion and depreciation:

The calculation of depletion at September 30, 2022 includes estimated future development costs of $1,114,671 (December 31, 2021 – $965,626) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of $90,218 (December 31, 2021 – $89,442).

(c) Impairment (reversal):

At September 30, 2022 there were no indicators of impairment or reversal of impairment identified on any of the Company's CGUs within property, plant and equipment and no impairment or reversal of impairment tests were performed which is consistent with the September 30, 2021 assessment.

For the nine months ended September 30, 2021, an 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 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.

(d) Right-of-use assets:

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

	Field operations	Office leases	Total
Balance at December 31, 2020	$6,191	$187	$6,378
Lease additions	–	1,914	1,914
Leases acquired	1,551	73	1,624
Depletion and depreciation	(1,926)	(474)	(2,400)
Impairment reversal	2,225	–	2,225
Balance at December 31, 2021	8,041	1,700	9,741
Lease additions	1,283	1,401	2,684
Depletion and depreciation	(1,985)	(789)	(2,774)
Balance at September 30, 2022	$7,339	$2,312	$9,651

7. Exploration and evaluation assets:

	Total
Cost:	
Balance at December 31, 2020	$26,274
Additions	3,595
Disposal	(3,169)
Transfer to property, plant and equipment (note 6)	(532)
Balance at December 31, 2021	26,168
Additions	47,827
Transfer to property, plant and equipment (note 6)	(3,148)
Balance at September 30, 2022	$70,847
Accumulated amortization and impairment:	
Balance at December 31, 2020	$24,814
Amortization	715
Disposal	(3,169)
Balance at December 31, 2021	22,360
Amortization	1,884
Balance at September 30, 2022	$24,244

	Total
Carrying amounts:	
At December 31, 2021	$3,808
At September 30, 2022	$46,603

Exploration and evaluation additions for the nine months ended September 30, 2022 includes approximately $43.6 million of undeveloped prospective lands in the Greater Peavine Clearwater area.

8. Acquisitions and dispositions:

Acquisitions:

On June 10, 2022 the Company completed the Rolling Hills Energy Ltd., Southern Clearwater oil acquisition for total cash consideration of $49.3 million, including $2.8 million of capitalized transaction costs, and the issuance of 9.3 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $6.34 per common share, the total consideration was approximately $108.1 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. Oil and natural gas 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:

		Amount
Net assets acquired:		
Oil and natural gas interests	$	127,704
Current assets		13,694
Current liabilities		(13,689)
Risk management contracts		(14,873)
Decommissioning obligations		(4,701)
Net assets acquired	**$**	**108,135**
Purchase consideration:		
Cash consideration	$	49,321
Share consideration (9,276,644 common shares)		58,814
Total purchase consideration	**$**	**108,135**

On February 15, 2022 the Company completed the Crestwynd Exploration Ltd., Southern Clearwater oil acquisition for total cash consideration of $98.9 million including $4.4 million of capitalized transaction costs and the issuance of 26.3 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $4.92 per common share, the total consideration was approximately $228.3 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. Oil and natural gas 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:

		Amount
Net assets acquired:		
Oil and natural gas interests	$	228,065
Current assets		15,472
Current liabilities		(12,306)
Decommissioning obligations		(2,917)
Net assets acquired	**$**	**228,314**
Purchase consideration:		
Cash consideration	$	98,926
Share consideration (26,298,389 common shares)		129,388
Total purchase consideration	**$**	**228,314**

On October 13, 2022 the Company successfully closed the previously announced acquisition of Deltastream Energy Corporation ("Deltastream"). Deltastream was a privately held pure-play Clearwater oil producer that held a leading economic drilling inventory of high-quality, long-life assets. The Deltastream acquisition strategically positions Tamarack as the largest producer in the Clearwater oil fairway. Tamarack acquired all of the issued and outstanding common shares of Deltastream for total consideration of approximately $1.425 billion consisting of 80 million common shares of Tamarack, $300 million of deferred acquisition payment notes and $825 million in cash.

Dispositions:

For the nine months ended September 30, 2022 the Company disposed of a gross overriding royalty (between 2% and 5%) on a select portion of the Clearwater and Charlie Lake properties for consideration of $14.9 million and recorded a gain on disposition of $2.2 million.

On July 21, 2022 the Company disposed of non-core Viking oil CGU assets for net consideration of approximately $59.5 million (inclusive of a $20.0 million promissory note at 12% interest per annum maturing on July 21, 2025) and recorded a gain on disposition of $2.7 million.

The Company also disposed of non-core properties for proceeds of $0.6 million.

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 $271.5 million at September 30, 2022 (December 31, 2021 – $273.4 million), which is expected to be incurred between 2022 and 2050. A risk-free rate of 3.1% (December 31, 2021 – 1.7%) and an inflation rate of 1.8% (December 31, 2021 – 1.8%) is used to calculate the present value of the decommissioning obligations at September 30, 2022 as presented in the table below:

	Nine months ended September 30, 2022	Year Ended December 31, 2021
Balance, beginning of the period	**$284,472**	$245,437
Liabilities incurred	**5,552**	8,955
Liabilities acquired (note 8)	**7,618**	21,702
Change in estimates	**(50,709)**	(3,687)
Change in discount rate on acquisition	**9,333**	18,305
Expenditures	**(5,429)**	(4,466)
Site rehabilitation program grant (note 19)	**(2,198)**	(5,365)
Liabilities disposed	**(15,911)**	(1,304)
Accretion	**5,085**	4,895
Balance, end of the period	**$237,813**	$284,472

Revisions due to the change of discount rate on acquisitions of $9.3 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, 2022 resulted from decommissioning obligations being revalued using a risk-free discount rate of 3.1% and an inflation rate of 1.8% as opposed to a risk-free discount rate of 1.7% and an inflation rate of 1.8% used at December 31, 2021.

As at September 30, 2022 approximately $2.2 million was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work (December 31, 2021 – $5.4 million).

Timing of decommissioning obligation expenditures expected to be incurred are:

	As at September 30, 2022
Decommissioning obligations – Less than 1 year	$11,200
Decommissioning obligations – Greater than 1 year	226,613
Total	$237,813

10. Lease liabilities:

The Company has lease liabilities for contracts related to financing processing facilities and equipment, 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, 2022 were between 4.0% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at September 30, 2022:

	Nine months ended September 30, 2022	Year Ended December 31, 2021
Balance, beginning of the period	**$10,532**	$10,154
Lease additions	**2,684**	1,914
Leases acquired	**–**	1,624
Interest expense	**564**	791
Lease payments	**(3,381)**	(3,951)
Balance, end of the period	**$10,399**	$10,532
Current portion	**$4,038**	$3,600
Long term portion	**$6,361**	$6,932

Undiscounted cash outflows relating to the lease liabilities are:

	Nine months ended September 30, 2022	Year Ended December 31, 2021
Less than 1 year	**$4,585**	$4,099
Years 2 and 3	**5,570**	6,369
Years 4 and 5	**941**	2,414
Thereafter	**366**	1,745
Total	**$11,462**	$14,627

11. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Source/(use) of cash:				
Accounts receivable	**$55,540**	$(13,370)	**$(32,929)**	$(63,918)
Prepaid expenses and deposits	**509**	523	**(3,614)**	(2,836)
Accounts payable and accrued liabilities	**23,084**	19,576	**111,434**	58,458
Interest payable on senior unsecured notes	**(3,648)**	–	**(5,860)**	–
Dividends payable	**(4,769)**	–	**(4,769)**	–
Working capital acquired (note 8)	**–**	–	**3,166**	10,646
	$70,716	$6,729	**$67,428**	$2,350
Related to operating activities	**$35,150**	$243	**$(634)**	$(25,930)
Related to financing activities	**$(4,417)**	$ –	**$1,120**	$(1,005)
Related to investing activities	**$39,983**	$6,486	**$66,942**	$29,285

The following are included in cash provided by operating activities:

	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Interest and fees on SLL facility and SL Notes	**$4,128**	$6,261	**$16,529**	$13,898
Interest on lease liabilities	**$185**	$211	**$564**	$596

12. Credit Facilities

As at September 30, 2022 the principal amount of borrowings outstanding under our sustainability-linked lending facility (‘SLL facility”) was $nil, as a result of $39.5 million of net cash proceeds from the Viking oil CGU disposition, the issuance of an additional $100.0 million of SL Notes, net proceeds of $137.3 million from the issuance of common shares and the generation of funds flow in the current quarter. The net proceeds of issuance of the SL Notes and the common shares were used to partially fund the Deltastream acquisition which closed on October 13, 2022.

Subsequent to September 30, 2022 the Company established a new three-year covenant-based SLL facility, replacing the existing SLL facility, which increased the SLL facility to $700 million and is paired with a $260 million two-year secured amortizing term-loan (“Term Facility”) from a syndicate of lenders (“Syndicated Facility”). The Syndicated Facility is secured by a $2.0 million debenture with fixed coverage over all the assets of the Company. The SLL portion of the facility bears interest at the applicable rate for the borrowing employed plus a credit margin based on the senior debt to EBITDA ratio of the Company.

As the SLL facility is a covenant-based facility, it is not contingent of the reserve base and not subject to annual or semi-annual redeterminations. The SLL facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower. There are no mandatory principal repayments required prior to maturity.

The SLL facility contains commercial covenants in addition to financial covenants detailed below.

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

- Greenhouse Gas Emissions Intensity: 39% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline, with a significant decrease in 2021 and more ratable 5% decreases through 2022 to 2025. This SPT exceeds the previous set target due to 2021 acquisitions and positive progress in emissions reductions to date.
- Decommissioning Management: committed annual capital investment in abandonment, remediation and reclamation activities at 150% of the Alberta Energy Regulator inventory reduction voluntary closure program targets. This target is equivalent to ~4.33% of inactive liabilities in 2021 with a 5% annual escalation.
- Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025 with annual milestones and minimum of two additions each year.

The Term Facility is a non-revolving facility with a maturity date of October 13, 2024 and may be extended for a single twelve-month term at the request of the borrower and the discretion of the lenders. Minimum quarterly amortization payments are required beginning in January 2023 with the balance due and payable at maturity. The term-loan portion of the facility bears interest at the applicable rate for the borrowing employed plus a fixed margin rate.

Financial Covenants:

The following table summarizes the financial covenants applicable to the SLL Facility after September 30, 2022:

Covenant Description	Covenant(5)
Total Debt(1) to EBITDA(2) Ratio	3.0:1.0
Senior Debt(3) to EBITDA(2) Ratio	2.5:1.0
Debt Service Coverage(4) Ratio	1.5:1.0

(1) "Total Debt" is calculated in accordance with the credit facility agreements as all Debt of the Company excluding capitalized lease obligations and Letters of Credit and including indebtedness under the deferred acquisition notes issued on closing of the Deltastream acquisition.

(2) "EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on the previous four quarters including the impact of material acquisitions as if they had occurred at the beginning of the four quarters.

(3) "Senior Debt" is calculated in accordance with the credit facility agreements as Total Debt minus permitted junior debt, including the deferred acquisition notes.

(4) "Debt Service Coverage" is calculated as the ratio of EBITDA to cash interest expense plus scheduled principal payments on Total Debt for the twelve months ending at the end of each fiscal quarter.

(5) Covenants in effect while the term loan and deferred acquisition notes are outstanding after which time the covenants will change to 3.5:1.0, 3.0:1.0 and 3.0:1.0 respectively.

13. Senior unsecured notes:

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

On September 22, 2022 the Company issued an additional $100 million SL Notes due May 10, 2027. The SL Notes were offered through a private placement agreement entered into on September 12, 2022. The SL Notes were issued at a discounted principal amount (plus accrued interest from and including May 10, 2022) under the trust indenture pursuant to which Tamarack previously issued the existing SL Notes.

The SL Notes were issued in accordance with the Company's Sustainability-Linked Bond Framework which sets out certain sustainability performance targets on the SL Notes ("NSPTs") including:

- NSPT 1 - Greenhouse Gas Emissions Intensity: 39% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline.
- NSPT 2 - Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025.

Failure to meet the NSPTs will result in an increase in the interest rate payable of 75 basis points for the Greenhouse Gas Emissions Intensity reduction target and 25 basis points for the Indigenous Workforce Participation target from and including May 10, 2026.

The SL Notes are not governed by any financial covenants but contain a debt incurrence covenant that may restrict the Company's ability to raise additional senior debt beyond our existing SLL Facility and SL Notes.

The SL Notes pay interest semi-annually in arrears with the principal amount repayable at maturity. The SL Notes are redeemable at the Company's option, in whole or in part, at specified redemption prices, plus any accrued and unpaid interest up to the date of redemption, as noted in the following table:

	NSPTs Satisfied - Redemption percentages			
Redemption period	1 & 2	1	2	Neither
Prior to May 10, 2024[(1)]	108.250	108.250	108.250	108.250
May 10, 2024 - May 9, 2025	103.625	103.750	104.000	104.125
May 10, 2025 - May 9, 2026	101.813	101.875	102.000	102.063
May 10, 2026 - November 9, 2026	100.000	100.250	100.750	101.000
November 10, 2026 - May 9, 2027	100.000	100.125	100.375	100.500

(1) Redemption by the Company prior to May 10, 2024 of up to 40% of the aggregate principal outstanding upon issuance of an Equity Offering by the Company.

Upon the occurrence of a change of control, the SL Note holders may require the Company to repurchase such holders' SL Notes, in whole or in part, at a purchase price in cash of at least 101% of the aggregate principal amount of the SL Notes repurchased, plus accrued and unpaid interest.

On May 10, 2022, the Company made its first coupon payment of $3.5 million. The next coupon payment date is set for November 10, 2022 in the amount of approximately $10.9 million.

As at September 30, 2022 the carrying value of the SL Notes of approximately $287.4 million was net of approximately $12.6 million of discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at September 30, 2022 there was $300.0 million principal outstanding on the SL Notes.

14. Other liabilities:

	September 30, 2022	December 31, 2021
Cash award incentive plan	**$4,738**	$ –
Current other liabilities	**$4,738**	$ –
Cash award incentive plan	**$3,764**	$ –
Government loan	**4,310**	1,100
Long-term other liabilities	**$8,074**	$1,100

(a) Cash settled share units and incentive awards:

Effective March 9, 2022, PRSUs granted prior to that date for the Company's "Insiders" (Insiders as defined in securities legislation, excluding Directors of the Company) upon vesting will be settled in cash. For all other non-insiders participating in the PRSU plan, the PRSU awards will continue to be equity-settled. The value of the share awards to Insiders PRSUs, granted prior to March 9, 2022, were reclassified from Contributed Surplus to Other Liabilities on the Condensed Consolidated Interim Balance Sheet. The fair value of PRSUs that are accounted for as cash-settled transactions are subsequently adjusted to the underlying Common Share price at each period end.

On March 9, 2022, the Company's Board of Directors approved the implementation of a new Cash Award Incentive Plan, which will be used for future RIA and PIA grants that will be cash-settled. Both insiders and non-insiders are eligible for grants of awards under the new Cash Award Incentive Plan.

For the three and nine months ended September 30, 2022, the Company paid $0.2 million and $6.7 million, respectively, to cash settle 1.3 million RSU and PSU awards.

(b) Government loan:

As at September 30, 2022 the Company has recorded $4.3 million of government assistance that is repayable under the terms of the Federal Government of Canada Emissions Reduction Fund ("ERF") agreement, related to the Company's construction of a methane conservation program. The ERF agreement includes scheduled repayments for the repayable funding of approximately $0.6 million on March 31, 2025, $1.9 million on March 31, 2026 and a final payment of $3.3 million on March 31, 2027. The repayable government loan funding will be interest-free based on the Company's compliance with the terms and conditions of the ERF funding agreement and all repayments made in accordance with the above noted repayment schedule.

15. Finance expense:

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Interest and fees on credit facilities	**$4,591**	$6,261	**$14,456**	$13,898
Interest and fees on senior unsecured notes	**4,102**	–	**10,121**	–
Interest on lease liabilities	**185**	211	**564**	596
Accretion on government loan	**96**	–	**282**	–
Unrealized loss (gain) on foreign exchange	**(10,500)**	(6,033)	**343**	1,426
Unrealized loss (gain) on cross-currency swap	**9,884**	6,039	**(292)**	(1,410)
Accretion of decommissioning obligations	**2,061**	1,330	**5,085**	3,474
Total finance expense	**$10,419**	$7,808	**$30,559**	$17,984

16. Shareholders' equity:

(a) Share capital:

	September 30, 2022		December 31, 2021	
($ thousands)	Number	Amount	Number	Amount
Balance, opening	406,938,099	$1,242,392	262,776,395	$876,124
Issue of common shares - cash	38,334,100	143,753	33,333,300	75,000
Issue of common shares - acquisitions	35,575,033	188,202	110,230,769	290,427
Issue of common shares - cash on stock options	–	–	481,667	1,623
Issue of common shares - Option, RSU and PSU exercise	3,446,434	–	4,047,343	–
Issue on settlement of preferred shares	–	–	307,025	1,104
Purchase of common shares - cancellation	(4,362,700)	(14,375)	–	–
Return of common shares to treasury	–	(2,646)	–	–
Purchase of common shares - Option, RSU and PSU exercise	(3,529,100)	–	(4,238,400)	–
Transfer on stock option exercise	–	–	–	1,023
Share issue costs, net of tax (2022 - $1,475; 2021 - $869)	–	(4,937)	–	(2,909)
Balance, ending	476,401,866	$1,552,389	406,938,099	$1,242,392

At September 30, 2022 and at December 31, 2021 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

On September 27, 2022 the Company issued 38,334,100 shares at $3.75 per common share for gross proceeds of $143.8 million. Share issue costs in the amount of $6.4 million were incurred in association with the private placement.

(b) Normal course issuer bid:

Pursuant to the NCIB, the Company is permitted to purchase up to 20.4 million Common Shares over a period of twelve months commencing on November 3, 2021. During the nine months ended September 30, 2022, the Company purchased and cancelled 4.4 million Common Shares at an average price of $4.26 per Common Share, for a total repurchase cost of $18.6 million. For the year ended December 31, 2021 the Company did not purchase and cancel any Common shares.

(c) Treasury shares:

During the nine months ended September 30, 2022, the Company spent $17.3 million to purchase 3.5 million Common Shares to be used to settle stock options ("Stock Options"), RSUs and PSUs on the date of exercise. As at September 30, 2022, 538,798 Common Shares remain classified as treasury shares to be used for future settlements of Stock Options, RSUs and PSUs (December 31, 2021 - 937,799 Common Shares).

(d) Dividends:

During the nine months ended September 30, 2022, the Company paid $31.0 million related to its monthly cash dividends on its common shares of $0.0083 per share for the first five months of 2022 and $0.01 per share for all dividends declared on and after June 15, 2022 and accrued a dividend payable of $4.8 million on its common shares of $0.01 per share for the dividend declared on September 15, 2022.

The Company's Board of Directors declared the monthly cash dividend of $0.01 per share on October 15, 2022 payable on November 15, 2022 to shareholders of record at the close of business on October 31, 2022.

On September 12, 2022, the Company announced an increase to its monthly dividend of 25% to $0.0125 per month beginning with the November declaration with an anticipated dividend payment date of December 15, 2022.

These monthly cash dividends are designated as "eligible dividends" for Canadian income tax purposes.

17. Net income per share:

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except per share amounts)	**2022**	2021	**2022**	2021
Net Income	**$124,793**	$20,032	**$294,757**	$250,060
Weighted average shares - basic	**440,388**	406,152	**431,672**	335,913
Weighted average shares - diluted	**443,351**	414,342	**435,053**	344,072
Net Income per share-basic	**$ 0.28**	$ 0.05	**$ 0.68**	$ 0.74
Net Income per share-diluted	**$ 0.28**	$ 0.05	**$ 0.68**	$ 0.73

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the three and nine months ended September 30, 2022, 5.6 million and 5.8 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs and PSUs were included in the diluted weighted average number of Common Shares outstanding, respectively. 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 were included in the diluted weighted average number of Common Shares outstanding, respectively.

18. Share-based payments:

The following table summarizes stock-based compensation expense relating to Stock Options, RSUs, PSUs, RIAs and PIAs:

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Stock Options	**$40**	$161	**$135**	$405
RSUs	**1,219**	893	**3,114**	2,539
PSUs	**335**	610	**1,272**	3,804
Equity settled stock-based compensation	**$1,594**	$1,664	**$4,521**	$6,748
RSUs	**$(360)**	$ –	**$151**	$ –
PSUs	**(839)**	–	**–**	–
RIAs	**356**	–	**675**	–
PIAs	**189**	–	**594**	–
Cash settled stock-based compensation	**$(654)**	$ –	**$1,420**	$ –
Total capitalized costs	**$(531)**	$(506)	**$(2,196)**	$(2,957)
Total expensed stock-based compensation	**$409**	$1,158	**$3,745**	$3,791

Pursuant to the Company's stock option plan (the "Stock Option Plan"), the Company's performance and restricted share unit plan (the "PRSU Plan") and the Company's cash award incentive plan (the "CAI Plan"), the Company may grant up to an aggregate of 33.3 million Stock Options, RSUs, PSUs, RIAs and PIAs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable.

(a) Stock Options:

As at September 30, 2022, there were 1.4 million Stock Options 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 no Stock Options granted during the nine months ended September 30, 2022 (December 31, 2021 – 0.9 million).

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

	Number of Stock Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2021	1,904	$2.51
Granted	868	2.33
Exercised	(482)	3.37
Forfeited/expired	(148)	2.85
Outstanding, December 31, 2021	2,142	$2.22
Exercised – issuance of shares from treasury	(620)	2.73
Forfeited/expired	(118)	2.29
Outstanding, September 30, 2022	**1,404**	**$1.99**

The range of exercise prices of the Stock Options outstanding and exercisable at September 30, 2022 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	996	$1.75	3.0	463	$1.54
$ 2.51 – 2.66	408	$2.60	1.6	335	$2.59
$ 0.64 – 2.66	**1,404**	**$1.99**	**2.6**	**798**	**$1.98**

(b) PRSU Plan:

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors, and PSUs to officers, employees, and consultants of the Company or its subsidiaries. Each RSU entitles the holder upon settlement 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 by receipt of one Common Share in accordance with the PRSU Plan. Each PSU entitles the holder upon settlement 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 by receipt of one Common Share in accordance with the PRSU Plan. An RSU or PSU holder may also elect to have RSUs or PSUs settled in exchange for a payment by the Company of a cash amount per RSU or

PSU equal to the closing price of the Common Shares before the distribution date for the settlement of the RSUs or PSUs, provided; however, that the Company has the sole discretion to consent or refuse the election to receive cash.

Effective March 9, 2022, PRSUs granted prior to that date for the Company's "Insiders" (Insiders as defined in securities legislation, excluding Directors of the Company) upon vesting will be settled in cash. For all other non-insiders participating in the PRSU plan, the PRSU awards will continue to be equity-settled. The value of the share awards to Insiders PRSUs, granted prior to March 9, 2022, were reclassified from Contributed Surplus to Other Liabilities on the Condensed Consolidated Interim Balance Sheet. The fair value of PRSUs that are accounted for as cash-settled transactions are subsequently adjusted to the underlying Common Share price at each period end.

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.

For the purpose of calculating stock-based compensation for non-cash settled RSUs and PSUs, the fair value of each RSU or PSU is determined at the grant date using the closing price of the Common Shares.

Based on the PRSU plan, the fair value of RSUs and PSUs are equal to the underlying Common Share price on grant date.

There were 1.5 million RSUs and 1.3 million PSUs granted during the nine months ended September 30, 2022 (December 31, 2021 – 2.2 million RSUs and 2.9 million PSUs).

The following table summarizes information about the RSUs and PSUs:

	Number of RSUs (thousands)	Number of PSUs (thousands)
Outstanding, January 1, 2021	5,365	3,564
Granted	2,186	2,918
Exercised - issuance of shares from treasury	(2,724)	(1,323)
Forfeited	(123)	(285)
Outstanding, December 31, 2021	4,704	4,874
Granted	1,495	1,298
Reinvestment of dividends	37	24
Exercised - issuance of shares from treasury	(1,994)	(834)
Exercised - cash payment	(680)	(570)
Forfeited	(263)	(670)
Outstanding, September 30, 2022(1)	**3,299**	**4,122**
Exercisable, September 30, 2022(2)	**4**	**–**

(1) As at September 30, 2022, there are 542 outstanding cash settled RSUs and 2,443 outstanding cash settled PSUs remaining.

(2) As at September 30, 2022, there are no exercisable cash settled RSUs and no exercisable cash settled PSUs remaining.

(c) Cash Award Incentive Plan:

On March 9, 2022, the Company's Board of Directors approved the implementation of a new Cash Award Incentive Plan, which will be used for future RIA and PIA grants that will be cash-settled. Both insiders and non-insiders are eligible for grants of awards under the new CAI Plan. The CAI Plan allows the Board of Directors to grant RIAs and PIAs to officers, employees and consultants of the Company or its subsidiaries. Each RIA entitles the holder upon settlement 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 by receipt of one Common Share in accordance with the CAI Plan. Each PIA entitles the holder upon settlement to an award value with respect to each notional Common Share underlying an incentive award on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times for each notional

Common Share award in accordance with the CAI Plan. Each RIA and PIA entitles the holder to an award value with respect to each notional Common Share underlying an incentive award, the amount, payable in cash, equal to the market value of the Company's Common Shares of each such notional Common Share calculated on the 20-day volume-weighted average price prior to the payment date.

Based on the CAI plan, the fair value of RIAs and PIAs are equal to the underlying Common Share price on grant date. The fair value of RIAs and PIAs are subsequently adjusted to the underlying Common Share price at each period end.

There were 0.5 million RIAs and 1.2 million PIAs granted during the nine months ended September 30, 2022 (December 31, 2021 – nil RIAs and nil PIAs).

The following table summarizes information about the RIAs and PIAs:

	Number of RIAs (thousands)	Number of PIAs (thousands)
Outstanding, January 1, 2022	–	–
Granted	494	1,152
Forfeited	(60)	(140)
Outstanding, September 30, 2022	**434**	**1,012**
Exercisable, September 30, 2022	**–**	**–**

19. Government assistance:

(a) Decommissioning obligations:

The Company has recorded $1.5 million and $2.2 million of combined SRP and ASCP support payments received as a reduction to decommissioning obligations and recorded other income from the site rehabilitation program grant on the condensed consolidated interim statement of income and comprehensive income for the three and nine months ended September 30, 2022, respectively (September 30, 2021 - $0.7 million and $2.1 million, respectively).

(b) Emissions reductions:

As at September 30, 2022 the Company has recorded $10.7 million of combined ERF and MTIP funding, of which $4.3 million is recognized as a government loan under the terms of the ERF agreement, related to the Company's construction of a methane conservation program. The ERF agreement includes scheduled repayments for the repayable funding on March 31, 2025, March 31, 2026 and March 31, 2027 (see note 14(b)).

20. Commitments:

The following table summarizes the Company's commitments as at September 30, 2022:

	2022	2023	2024	2025	2026+
Senior unsecured notes(1)	–	–	–	–	300,000
Interest on senior unsecured notes(1)	5,438	21,750	21,750	21,750	29,496
Lease(2)	87	347	347	261	–
Government loan(3)	–	–	–	579	5,207
Take or pay commitments(4)	1,820	4,265	540	–	–
Processing commitments(5)	288	1,150	2,886	4,622	25,130
Gas transportation(6)	1,399	4,737	1,538	10	–
Capital commitments(7)	–	9,819	35,000	–	–
Total(8)	9,032	42,068	62,061	27,222	359,833

(1) Principal amount of the notes. Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

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

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

(4) Pipeline commitments to deliver crude oil and or crude oil and condensate for various volumes ranging from minimums of 65 m3/d to 636 m3/d at various tariffs ranging from $9.00/m3 to $21.15/m3. These pipeline commitments are all in effect as at July 1, 2022 and last for various terms ending between December 31, 2023 and May 31, 2024. Certain of these pipeline commitments escalate at 2% per annum.

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

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

(7) Initial aggregate commitments of $255.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to March 31, 2024 of which $44.8 million is remaining to be incurred.

(8) Total commitments excludes commitments related to the Syndicated Facility of approximately $565.0 million, the Term Facility of $260.0 million (see note 12 Credit facilities) and deferred acquisition notes of $300.0 million to be used in partially funding the Deltastream acquisition which closed on October 13, 2022.

21. 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)]

Kathleen Hogenson[(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

Ben Stoodley
VP Engineering

Christine Ezinga
VP Corporate Planning & Business Development

Scott Shimek
VP Production & Operations

Lynne Chrumka
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