



## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

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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, 2023 and 2022. This MD&A is dated and based on information available as at October 25, 2023 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, 2023 and 2022 and the audited consolidated financial statements for the year ended December 31, 2022. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2022, is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) and Tamarack's website at [www.tamarackvalley.ca](http://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 22. Unless otherwise indicated, all references to dollar amounts are in Canadian ("CAD") currency.

### Highlights for the Three and Nine Months Ended September 30, 2023

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**Production** – Average daily production reached a record 68,597 boe/d in the quarter, 58% higher than 2022 due to a successful 2023 development program in the Clearwater and Charlie Lake and acquisitions that closed in 2022. Liquids weighting of 82% oil and NGLs was 8% higher than last year. Year to date production of 67,760 boe/d is also 58% higher than prior year.

**Realizations** - Tamarack's average realized price was \$80.22/boe in the quarter, 22% higher than the second quarter of 2023 and consistent with the same period in 2022. Global crude oil prices rallied in the summer of 2023 and Canadian oil differentials narrowed. The Company's realized heavy oil price, net of blending expense, of \$92.85/bbl in the quarter was only \$0.24/bbl under the Hardisty benchmark price compared to a \$4.22 differential in the same quarter of 2022. Tamarack achieved stronger than historical oil price realizations as transportation and logistics improvements enabled production to move to more competitive sales points.

**Lifting Costs** - Net production expenses dropped to \$8.47/boe during the third quarter compared to \$10.25 in the second quarter as a result of the Company's new Wembley facilities being brought online in the Charlie Lake light oil play, additional infrastructure development in the Clearwater area and higher production.

**Capital** – Capital investments of \$122.8 million in the quarter and \$388.8 million year to date were focused on the Company's core development programs. Year to date, Tamarack drilled, completed and equipped 93 (91.6 net) Clearwater heavy oil wells and 14 (13.8 net) Charlie Lake light oil wells. Major infrastructure investments included work in the Clearwater Nipisi on a gas conservation and an oil treating and water injection facility, as well as the construction of the Wembley gas plant. Targeted infrastructure investment facilitated production growth, operating cost reductions and greenhouse gas emissions abatement.

**Adjusted Funds Flow & Free Cash Flow**- Record production and strong Canadian oil prices generated Adjusted Funds Flow of \$255.2 million in the third quarter of 2023, which was 44% higher than the same quarter in 2022. Free funds flow of \$132.4 million was \$53.0 million, or 67%, higher than the same quarter last year.

**Debt & Return of Capital** – With Free Funds Flow, combined with the \$39.5 million non-core disposals in July 2023 and \$100.2 million Cardium net assets held for sale, net debt was reduced to \$1,128.0 million at September 30, 2023, down \$246.0 million (17%) from June 30, 2023. \$20.9 million of base dividends were paid to shareholders in the quarter. The second half of 2023 is a step change for the Company's profitability and returns as free cash flow generation ramps up and net debt approaches the enhanced return threshold of \$1.1 billion.

The third quarter results demonstrate positive change in the business through focusing on top tier plays, margin enhancing infrastructure investments and improved price realizations.

## Annual Guidance

The Company's exploration and development capital guidance range remains unchanged at \$425 million to \$475 million. Tamarack continues to focus on maximizing free funds flow for debt repayment and enhancing shareholder returns as debt thresholds are met. Fourth quarter 2023 free funds flow is expected to reflect increased oil weighting with lower operating expenses driving improved netback realizations through the Company's infrastructure initiatives.

Tamarack has updated its 2023 production guidance to reflect the west central non-core Cardium asset disposition previously announced on 1 October 19, 2023. Updated full year 2023 production is expected to be in the range of 65,500 to 69,500 boe/d with fourth quarter volumes of 65,000 to 66,000 boe/d. Production guidance reflects the strong performance from the Clearwater and Charlie Lake drilling programs and the impact of the non-core Cardium disposition of ~4,500 boe/d for the fourth quarter. Tamarack expects to provide the 2024 budget and guidance on December 6, 2023.

	Prior guidance for the year ended December 31, 2023	Updated current guidance for the year ended December 31, 2023
	As presented May 10, 2023	As presented October 25, 2023
Capital expenditures (\$mm) <sup>(1)</sup>	<b>\$425 - \$475</b>	<b>\$425 - \$475</b>
Annual average production (boe/d) <sup>(5)</sup>	<b>67,000 - 71,000</b>	<b>65,500 - 69,500</b>
Average oil & NGL weighting	<b>81% - 83%</b>	<b>82% - 84%</b>
Expenses:		
Royalty rate (percent of sales - %)	<b>19% - 21%</b>	<b>19% - 21%</b>
Net production (\$/boe) <sup>(2)</sup>	<b>\$9.00 - \$9.50</b>	<b>\$9.00 - \$9.50</b>
Transportation (\$/boe)	<b>\$3.50 - \$4.00</b>	<b>\$3.50 - \$4.00</b>
General and administrative (\$/boe)	<b>\$1.25 - \$1.35</b>	<b>\$1.25 - \$1.35</b>
Interest (\$/boe)	<b>\$3.80 - \$4.00</b>	<b>\$3.80 - \$4.00</b>
Taxes (\$/boe) <sup>(3)(4)</sup>	<b>\$3.75 - \$4.10</b>	<b>\$3.75 - \$4.50</b>
Leasing expenditures (\$mm)	<b>\$3.5 - \$4.5</b>	<b>\$3.5 - \$4.5</b>

<sup>(1)</sup> Capital E&D budget includes exploration and development capital, environmental, social and governance ("ESG") initiatives, and facilities but excludes asset acquisitions and dispositions, ARO, land and seismic.

<sup>(2)</sup> Refer to the section "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures".

<sup>(3)</sup> Tax costs per boe are particularly sensitive to changes in commodity pricing and are represented in the guidance under the Company's best outlook of budget and strip pricing but may change significantly under alternate price conditions throughout the year.

<sup>(4)</sup> Tax guidance has been updated from percentage of net operating income to cost per boe for the prior and updated guidance for the year ended December 31, 2023.

<sup>(5)</sup> Prior guidance Annual Average Production is comprised of 16,500-17,500 bbl/d light and medium oil, 34,750-36,500 bbl/d heavy oil, 3,500-4,500 bbl/d NGL and 71,000-75,000 mcf/d natural gas. Current guidance Annual Average Production 16,400-16,900 bbl/d light and medium oil, 34,700-36,500 bbl/d heavy oil, 3,230-4,260 bbl/d NGL and 67,000-71,000 mcf/d natural gas.

## Q3 2023 Operational and Financial Highlights

	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
<b>(\$ thousands, except per share)</b>						
Total oil, natural gas revenue	506,365	327,910	54	1,284,066	1,033,135	24
Cash flow from operating activities	199,756	299,927	(13)	415,645	577,488	(28)
Per share – basic	\$ 0.36	\$ 0.52	(31)	\$ 0.75	\$ 1.34	(44)
Per share – diluted	\$ 0.36	\$ 0.52	(31)	\$ 0.74	\$ 1.33	(44)
Adjusted funds flow <sup>(1)</sup>	255,199	177,834	44	569,723	530,315	7
Per share – basic <sup>(3)</sup>	\$ 0.46	\$ 0.40	15	\$ 1.02	\$ 1.23	(17)
Per share – diluted <sup>(3)</sup>	\$ 0.46	\$ 0.40	15	\$ 1.02	\$ 1.22	(16)
Net income	8,634	124,793	(93)	36,874	294,757	(87)
Per share – basic	\$ 0.02	\$ 0.28	(93)	\$ 0.07	\$ 0.68	(90)
Per share – diluted	\$ 0.02	\$ 0.28	(93)	\$ 0.07	\$ 0.68	(90)
Net debt <sup>(1)</sup>	(1,128,030)	(286,762)	293	(1,128,030)	(286,762)	293
Capital expenditures <sup>(1)</sup>	122,759	98,451	25	388,752	333,301	17
<b>Weighted average shares outstanding (thousands)</b>						
Basic	556,708	440,388	26	556,399	431,672	29
Diluted	558,569	443,351	26	559,958	435,053	29
<b>Share Trading</b>						
High	\$ 4.12	\$ 4.62	(11)	\$ 4.88	\$ 6.48	(25)
Low	\$ 3.19	\$ 3.28	(3)	\$ 2.99	\$ 3.28	(9)
Average daily share trading volume (thousands)	1,975	3,745	(47)	2,457	3,890	(37)
<b>Average daily production</b>						
Light oil (bbls/d)	16,974	16,229	5	16,797	17,437	(4)
Heavy oil (bbls/d)	35,900	13,183	172	35,229	10,524	235
NGL (bbls/d)	3,623	3,659	(1)	3,795	3,769	1
Natural gas (mcf/d)	72,597	62,428	16	71,633	66,839	7
Total (boe/d)	68,597	43,476	58	67,760	42,870	58
<b>Average sale prices</b>						
Light oil (\$/bbl)	107.83	111.80	(4)	98.30	119.53	(18)
Heavy oil, net of blending expense <sup>(2)</sup> (\$/bbl)	92.85	89.30	4	76.15	99.48	(23)
NGL (\$/bbl)	41.46	49.18	(16)	41.51	56.23	(26)
Natural gas (\$/mcf)	2.60	6.27	(59)	2.84	6.59	(57)
Total (\$/boe)	80.22	81.98	(2)	69.29	88.28	(22)
<b>Operating netback (\$/Boe)</b>						
Average realized sales, net of blending expense <sup>(2)</sup>	80.22	81.98	(2)	69.29	88.28	(22)
Royalty expenses	(13.38)	(14.06)	(5)	(12.70)	(16.49)	(23)
Net production expenses <sup>(2)</sup>	(8.47)	(10.24)	(17)	(9.72)	(10.25)	(5)
Transportation expenses	(4.13)	(2.88)	43	(4.00)	(2.49)	61
<b>Operating field netback (\$/Boe) <sup>(2)</sup></b>						
Realized commodity hedging loss	(2.52)	(2.90)	(13)	(1.89)	(5.46)	(65)
<b>Operating netback (\$/Boe) <sup>(2)</sup></b>						
	51.72	51.90	–	40.98	53.59	(24)
<b>Adjusted funds flow (\$/Boe) <sup>(3)</sup></b>						
	40.44	44.46	(9)	30.80	45.31	(32)

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

<sup>(2)</sup> Non-IFRS Financial Ratio; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

<sup>(3)</sup> Supplemental Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

## Production

	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Production						
Light oil (bbls/d)	16,974	16,229	5	16,797	17,437	(4)
Heavy oil (bbls/d)	35,900	13,183	172	35,229	10,524	235
Natural gas liquids (bbls/d)	3,623	3,659	(1)	3,795	3,769	1
Natural gas (mcf/d)	72,597	62,428	16	71,633	66,839	7
Total (boe/d)	68,597	43,476	58	67,760	42,870	58
Percentage of oil and NGL	82%	76%	8	82%	74%	11

Average production for Q3 2023 and the nine months ended September 30, 2023 increased 58% compared to the same periods in 2022 due to the acquisitions that closed in the second half of 2022 and the 2023 development program, partially offset by expected declines of existing base production. Full year 2023 production guidance has been updated to be in the range of 65,500 to 69,500 boe/d to reflect the west central non-core Cardium asset disposition announced subsequent to Q3 2023.

The Company's oil and NGL weighting for the three and nine months ended September 30, 2023 was 82%, higher by 8% and 11%, respectively, as compared to the same periods in 2022 due to the acquisitions in the oil focused Clearwater play.

## Petroleum and Natural Gas Sales

	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Revenue (\$ thousands)						
Light oil	\$168,379	\$167,023	1	\$450,757	\$569,281	(21)
Heavy oil, net of blending expense <sup>(1)</sup>	306,663	108,308	183	732,392	285,804	156
Natural gas liquids	13,820	16,551	(17)	43,004	57,853	(26)
Natural gas	17,391	36,028	(52)	55,594	120,197	(54)
Total, net of blending expense <sup>(1)</sup>	\$506,253	\$327,910	54	\$1,281,747	\$1,033,135	24
Average realized price:						
Light oil (\$/bbl)	107.83	111.80	(4)	98.30	119.53	(18)
Heavy oil, net of blending expense (\$/bbl) <sup>(2)</sup>	92.85	89.30	4	76.15	99.48	(23)
Natural gas liquids (\$/bbl)	41.46	49.18	(16)	41.51	56.23	(26)
Combined average oil and NGL (\$/boe)	94.05	95.93	(2)	80.46	105.39	(24)
Natural gas (\$/mcf)	2.60	6.27	(59)	2.84	6.59	(57)
Revenue, net of blending expense (\$/boe) <sup>(2)</sup>	80.22	81.98	(2)	69.29	88.28	(22)
Benchmark pricing:						
West Texas Intermediate (US\$/bbl)	82.26	91.55	(10)	77.39	98.09	(21)
Edm Par Differential (US\$/bbl)	1.85	2.05	(10)	2.61	1.84	42
WCS differential (US\$/bbl)	12.88	19.86	(35)	17.63	15.73	12
Edmonton Par (Cdn\$/bbl)	107.90	116.79	(8)	100.63	123.41	(18)
Hardisty Heavy (Cdn\$/bbl)	93.09	93.52	–	80.38	105.54	(24)
NYMEX monthly settlement (US\$/mmbtu)	2.55	8.20	(69)	2.69	6.77	(60)
AECO daily index (Cdn\$/mcf)	3.40	4.00	(15)	3.00	5.24	(43)
AECO monthly index (Cdn\$/mcf)	2.37	5.77	(59)	3.01	5.55	(46)

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

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

Revenue per boe from oil, natural gas and NGL sales, net of blending expense, was \$80.22 per boe for Q3 2023 and \$69.29 per boe for YTD 2023 compared to \$81.98 per boe in Q3 2022 and \$88.28 per boe for YTD 2022. Quarter over quarter the net revenue held flat due to lower WTI being offset by a weaker Canadian dollar and improved heavy oil differentials. Canadian heavy and light oil differentials narrowed in the third quarter tied to higher North American refinery demand and seasonality. The YTD decrease in revenue per boe is primarily due to the lower WTI benchmark price, wider WCS and Edmonton Par differentials, as well as lower natural gas prices year over year. Oil's strength in Q3 compared to Q2 was driven by tight physical markets as a result of strong demand from high refinery utilization coupled with constrained supply from OPEC+, notably Saudi Arabia and Russia.

Comparing the Company's realized heavy oil price, net of blending expense, of \$92.85 per bbl for Q3 2023, to the Hardisty Heavy benchmark of \$93.09 per bbl, the Company has realized a tighter differential to previous periods. This change is due to an updated marketing approach, selling directly into the Edmonton market, which lead to improved netbacks and a shift of transportation costs from a revenue deduction to a transportation expense. Similarly, comparing the Company's realized heavy oil price, net of blending expense, of \$76.15 per bbl for YTD 2023, to the Hardisty Heavy benchmark of \$80.38 per bbl, is also an improvement over the same period in 2022 for the same reasons listed above. The WCS heavy oil differential strengthened year over year to an average of US\$12.88 per bbl in Q3 2023 compared to US\$19.86 per bbl due to the reduction of OPEC's production. Conversely, the WCS heavy oil differential weakened to US\$17.63 per bbl for YTD 2023 compared to US\$15.73 per bbl for the same period in 2022.

Comparing the Company's realized light oil price of \$107.83 per bbl for Q3 2023, to the Edmonton Light benchmark of \$107.90 per bbl, the Company has realized a tighter differential to previous periods. This change is due to improved netbacks and a shift of transportation costs from a revenue deduction to a transportation expense. Similarly, comparing the Company's realized light oil price of \$98.30 per bbl for YTD 2023, to the Edmonton Light benchmark of \$100.63 per bbl, is also an improvement over the same period in 2022 for the same reasons listed above. The Edmonton Par light oil differential strengthened to an average of US\$1.85 per bbl for Q3 2023 compared to US\$2.05 per bbl in Q3 2022. Conversely, the Edmonton Par light oil differential weakened to an average of US\$2.61 per bbl YTD 2023 compared to US\$1.84 per bbl in 2022 due to more overall light sweet supply in the 9 months of 2023.

The Company's realized NGL pricing decreased 16% and 26% for Q3 2023 and YTD 2023, respectively, compared to the same periods in 2022 largely due to the drop in WTI. The WTI benchmark price decreased 10% and 21% for Q3 2023 and YTD 2023, respectively, compared to the same periods in 2022.

Tamarack's realized natural gas price decreased to \$2.60 per mcf in Q3 2023 from \$6.27 per mcf in Q3 2022. The Company's YTD 2023 realized natural gas price decreased to \$2.84 per mcf from \$6.59 per mcf realized in 2022. Decreases in realized natural gas prices are consistent with decrease in AECO and NYMEX benchmarks.

## 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, 2023, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the tables below.

### Crude Oil Derivatives:

	Q4 2023		Q1 2024		Q2 2024		Q3 2024		Q4 2024	
<b>WTI 2-way Collar</b>										
<b>Volume (bbls/d)</b>	<b>20,000</b>		<b>21,000</b>		<b>19,500</b>		<b>11,500</b>		<b>3,000</b>	
Average Put/Call	67.00	87.54	66.93	86.30	69.36	89.39	68.85	93.13	67.50	92.09
Premium (USD/bbl)	1.93		0.93		1.00		1.38		1.33	
<b>Volume (bbls/d)</b>	<b>850</b>		-		-		-		-	
Average Put/Call (CAD/bbl)	80.44	108.64	-	-	-	-	-	-	-	-
<b>WTI Fixed Price</b>										
<b>Volume (bbls/d)</b>	<b>200</b>		-		-		-		-	
Average Fixed Price (CAD/bbl)	91.75		-		-		-		-	
<b>MSW Differential</b>										
<b>Volume (bbls/d)</b>	<b>2,500</b>		<b>2,500</b>		<b>3,000</b>		<b>4,000</b>		<b>4,000</b>	
Average Fixed Price (USD/bbl)	(2.55)		(2.69)		(2.73)		(2.63)		(2.63)	
<b>WCS Differential</b>										
<b>Volume (bbls/d)</b>	<b>14,000</b>		<b>4,500</b>		<b>4,000</b>		<b>500</b>		<b>500</b>	
Average Fixed Price (USD/bbl)	(16.57)		(14.76)		(13.57)		(13.75)		(13.75)	
<b>Volume (bbls/d)</b>	<b>700</b>		-		-		-		-	
Average Fixed Price (CAD/bbl)	(19.29)		-		-		-		-	

### Natural Gas Derivatives:

	Summer 23 <sup>(1)</sup>		Sept/Oct 23		Winter 23/24 <sup>(2)</sup>		Summer 24 <sup>(1)</sup>	
<b>AECO – NYMEX Basis</b>								
<b>Volume (mmbtu/d)</b>	<b>17,500</b>		-		<b>25,000</b>		<b>2,500</b>	
Average Fixed Price (USD/mmbtu)	(1.87)		-		(1.10)		(1.11)	
<b>AECO 5A Swap</b>								
<b>Volume (GJ/d)</b>	-		<b>25,000</b>		-		<b>1,000</b>	
Average Fixed Price (CAD/GJ)	-		2.36		-		2.80	
<b>NYMEX Collar</b>								
<b>Volume (mmbtu/d)</b>	<b>17,500</b>		-		<b>25,000</b>		<b>2,500</b>	
Average Put/Call (USD/mmbtu)	4.56	6.98	-	-	3.08	4.28	3.05	3.50

<sup>(1)</sup> Summer runs from April 1 to October 31 of the given year.

<sup>(2)</sup> Winter runs from November 1 to March 31 of the given year.

## Foreign Exchange Derivatives:

	Q4 2023		Q1 2024		Q2 2024		Q3 2024		Q4 2024	
<b>CAD/USD Collar</b>										
<b>Amount (USD/month)</b>	<b>\$12,000,000</b>		<b>\$3,000,000</b>		<b>\$3,000,000</b>		-		-	
Average Put/Call (CAD/USD)	1.3254	1.3909	1.3333	1.3885	1.3333	1.3885	-	-	-	-
<b>CAD/USD Variable Rate Collar</b>										
<b>Amount (USD/month)</b>	<b>\$11,500,000</b>		<b>\$18,500,000</b>		<b>\$18,500,000</b>		<b>\$6,000,000</b>		<b>\$6,000,000</b>	
Average Put/Call (CAD/USD) <sup>(1)</sup>	1.33	1.41	1.33	1.41	1.33	1.41	1.33	1.41	1.33	1.41
Knockout Rate (CAD/USD) <sup>(1)</sup>	1.36		1.36		1.36		1.36		1.36	
<b>CAD/USD Variable Rate Collar (Extendable Option)<sup>(2)</sup></b>										
<b>Amount (USD/month)</b>	<b>\$12,500,000</b>		<b>\$4,500,000</b>		<b>\$4,500,000</b>		<b>\$2,000,000</b>		<b>\$2,000,000</b>	
Average Put/Call (CAD/USD) <sup>(1)</sup>	1.33	1.41	1.33	1.41	1.33	1.41	1.32	1.40	1.32	1.40
Knockout Rate (CAD/USD) <sup>(1)</sup>	1.36		1.36		1.36		1.38		1.38	
<b>CAD/USD Swap</b>										
<b>Amount (USD/month)</b>	<b>\$6,000,000</b>		<b>\$5,000,000</b>		<b>\$5,000,000</b>		<b>\$3,000,000</b>		<b>\$3,000,000</b>	
Average Fixed Price (CAD/USD)	1.3399		1.3539		1.3539		1.3553		1.3553	
<b>Put Deferred Premium</b>										
<b>Amount (USD/month)</b>	-		<b>\$3,000,000</b>		-		-		-	
Average Put (CAD/USD)	-		1.32		-		-		-	
Average Premium (CAD/USD)	-		0.01		-		-		-	

<sup>(1)</sup> If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.

<sup>(2)</sup> Includes an extension option at the end of the collar, at the counterparty's option, for an equivalent term at an average rate forward fixed price equal to the call.

## Interest Rate Derivatives:

	2023	2024
<b>CDOR Swap</b>		
<b>Amount (million CAD\$/year)</b>	<b>30.0</b>	<b>6.3</b>
Average Interest Rate	1.047%	1.045%

At September 30, 2023, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of \$24.2 million (December 31, 2022 – \$10.3 million net liability) recorded on the balance sheet. The Company recorded an unrealized loss of \$20.1 million and a realized loss of \$15.9 million in earnings for the three months ended September 30, 2023, compared to an unrealized gain of \$47.8 million and a realized loss of \$11.6 million during the same period in 2022. The Company recorded an unrealized loss of \$13.9 million and a realized loss of \$34.9 million in earnings for the nine months ended September 30, 2023, compared to an unrealized gain of \$32.1 million and a realized loss of \$63.9 million during the same period in 2022. The unrealized and realized losses for the three and nine months ended September 30, 2023 were primarily due to the strength of WTI pricing. 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.

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, 2023, the Company held no physical commodity contracts.

## Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Royalty expenses (\$ thousands)	<b>\$84,443</b>	\$56,256	50	<b>\$234,875</b>	\$192,990	22
\$/boe	<b>13.38</b>	14.06	(5)	<b>12.70</b>	16.49	(23)
Percent of sales (%)	<b>17</b>	17	–	<b>18</b>	19	(5)

Royalties as a percentage of revenue for the three and nine months ended September 30, 2023 were consistent with the same periods in 2022. YTD royalty rates of 18% are under the guidance range due to lower reference commodity prices for most of the year. The Company expects royalty rates as a percentage of revenue to be in the 19% to 21% range for Q4 2023 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 2023 and the nine months ended September 30, 2023 compared to the same periods in 2022 due to an increase in production and GORRs, partially offset by decreased commodity prices.

## Net Production Expenses

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Production expenses	<b>\$54,602</b>	\$42,347	29	<b>\$181,072</b>	\$122,255	48
Less: processing income	<b>1,156</b>	1,394	(17)	<b>1,229</b>	2,259	(46)
Total net production expenses <sup>(1)</sup>	<b>\$53,446</b>	\$40,953	31	<b>\$179,843</b>	\$119,996	50
Total (\$/boe) <sup>(2)</sup>	<b>\$8.47</b>	\$10.24	(17)	<b>\$9.72</b>	\$10.25	(5)

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

<sup>(2)</sup> 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, 2023, per unit net production expenses (see “Non-IFRS Financial Ratios”) were lower compared to the same periods in 2022 due to our new facilities being brought on-line in Q3 2023 in conjunction with further synergies being realized across our Clearwater assets in the Nipisi and Marten Hills area as a result of the Deltastream acquisition. 2023 production expense outlook remains in line with our previous guidance of \$9.00 to \$9.50 per boe.

For the three and nine months ended September 30, 2023, on an absolute basis, gross and net production expenses were higher compared to the same periods in 2022 due to higher production.

## Transportation Expense

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Transportation expense - gas	\$3,144	\$2,890	9	\$8,093	\$8,737	(7)
Transportation expense - oil	22,890	8,621	166	65,969	20,406	223
Total transportation expense	\$26,034	\$11,511	126	\$74,062	\$29,143	154
Total (\$/boe)	\$4.13	\$2.88	43	\$4.00	\$2.49	61

<sup>(1)</sup> Pipeline tariffs are classified as transportation expenses when the Company has firm commitments or contractual arrangements on the pipeline. Pipeline tariffs may also be included indirectly as a deduction from the base price paid by a purchaser of the Company's oil, NGL and gas sales. In the latter case, the pipeline tariffs are included as a reduction of revenue rather than a transportation expense.

For the three months ended September 30, 2023, per unit transportation expenses were higher compared to the same period in 2022. The increase in oil transportation was driven by higher heavy oil trucking costs in order to optimize netbacks, increased pipeline tariffs and transportation costs shifting from a revenue deduction to a transportation expense due to new contractual arrangements. These factors result in an increase in realized pricing compared to Benchmark pricing which can be seen in the Petroleum and Natural Gas Sales section in this MD&A (page 4).

For the nine months ended September 30, 2023, per unit transportation expenses were higher compared to the same period in 2022 due to the 2022 acquisitions. Starting in Q2 2023, pipeline tariffs from light oil production have also been included as a transportation expense due to new contractual terms.

Total transportation expense for gas increased during the three months ended September 30, 2023 due to unplanned downtime and increases in tolls on the Nova Gas Transmission System. The YTD 2023 decrease in transportation costs for gas compared to the same period in 2022 was driven by the lower fuel costs in the first half of 2023. Total transportation expense for oil is inline with the increase in total production of heavy oil for both the third quarter of 2023 and YTD 2023.

## Blending Expense

Blending expense includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In this MD&A, blending expense is recognized as a reduction to heavy oil revenues (see "Non-IFRS Financial Measures").

Blending expense for the three and nine months ended September 30, 2023 was \$0.1 million and \$2.3 million, respectively, compared to \$nil in the same periods in 2022. Blending expense was lower in Q3 2023 compared to previous quarters in 2023 due to lower diluent requirements during the warmer summer months. The Company recognized blending expense for the first time in Q4/22 as a result of the Deltastream acquisition which closed in October 2022.

## Operating Netback

(\$/boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Average realized sales, net of blending expense <sup>(1)</sup>	<b>\$80.22</b>	\$81.98	(2)	<b>\$69.29</b>	\$88.28	(22)
Royalty expenses	<b>(13.38)</b>	(14.06)	(5)	<b>(12.70)</b>	(16.49)	(23)
Net production expenses <sup>(1)</sup>	<b>(8.47)</b>	(10.24)	(17)	<b>(9.72)</b>	(10.25)	(5)
Transportation expense	<b>(4.13)</b>	(2.88)	43	<b>(4.00)</b>	(2.49)	61
Operating field netback <sup>(1)</sup>	<b>\$54.24</b>	\$54.80	(1)	<b>\$42.87</b>	\$59.05	(27)
Realized hedging loss	<b>(2.52)</b>	(2.90)	(13)	<b>(1.89)</b>	(5.46)	(65)
Operating netback <sup>(1)</sup>	<b>\$51.72</b>	\$51.90	–	<b>\$40.98</b>	\$53.59	(24)

	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Average realized sales, net of blending expense <sup>(2)</sup>	<b>\$506,253</b>	\$327,910	54	<b>\$1,281,747</b>	\$1,033,135	24
Royalty expenses	<b>(84,443)</b>	(56,256)	50	<b>(234,875)</b>	(192,990)	22
Net production expenses <sup>(2)</sup>	<b>(53,446)</b>	(40,953)	31	<b>(179,843)</b>	(119,996)	50
Transportation expense	<b>(26,034)</b>	(11,511)	126	<b>(74,062)</b>	(29,143)	154
Operating field netback <sup>(2)</sup>	<b>\$342,330</b>	\$219,190	56	<b>\$792,967</b>	\$691,006	15
Realized hedging loss	<b>(15,922)</b>	(11,615)	37	<b>(34,892)</b>	(63,916)	(45)
Operating netback <sup>(2)</sup>	<b>\$326,408</b>	\$207,575	57	<b>\$758,075</b>	\$627,090	21

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

<sup>(2)</sup> Non-IFRS Financial Measure; 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, 2023 operating netback per boe (see “Non-IFRS Financial Ratios”) was lower than the same periods in 2022 primarily due to a decrease in commodity prices and higher transportation expenses partially offset by lower net production expenses.

On an absolute basis, operating netback (see “Non-IFRS Financial Measures”) was higher for Q3 2023 compared to the same period in 2022 due to higher production from the acquisitions that closed in 2022 partially offset by lower commodity prices, higher royalties, higher net production expenses and higher transportation expenses.

For the nine months ended September 30, 2023 operating netback (see “Non-IFRS Financial Measures”) on an absolute basis was higher compared to the same period in 2022 due to higher production from the Deltastream acquisition and a lower realized hedging loss, partially offset by lower commodity prices, higher royalties, higher net production expenses and higher transportation expenses.

## General and Administrative (“G&A”) Expenses

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Gross costs	\$10,781	\$7,745	39	\$31,951	\$25,576	25
Capitalized costs and recoveries	(2,842)	(1,934)	47	(8,453)	(5,308)	59
General and administrative costs	\$7,939	\$5,811	37	\$23,498	\$20,268	16
Total (\$/boe)	\$1.26	\$1.45	(13)	\$1.27	\$1.73	(27)

Net G&A costs on a per boe basis for the three and nine months ended September 30, 2023, were lower compared to the same periods in 2022 due to increased production from the acquisitions that closed in 2022, partially offset by increased staffing levels and growth-related cost increases.

For the three and nine months ended September 30, 2023, gross G&A costs were higher compared to the same periods in 2022, due to increased staffing levels and other growth-related cost increases.

## Stock-Based Compensation Expense

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Stock Options	\$25	\$40	(38)	\$112	\$135	(17)
RSUs	1,949	1,219	60	5,683	3,114	82
PSUs	649	335	94	1,843	1,272	45
Equity settled	\$2,623	\$1,594	65	\$7,638	\$4,521	69
RSUs	\$(17)	\$(360)	(95)	\$376	\$151	149
PSUs	564	(839)	(167)	4,385	–	–
RIAs	430	356	21	1,487	675	120
PIAs	792	189	319	2,144	594	261
Cash settled	\$1,769	\$(654)	(370)	\$8,392	\$1,420	491
Total capitalized costs	\$(1,442)	\$(531)	172	\$(3,497)	\$(2,196)	59
Total expensed stock-based compensation	\$2,950	\$409	621	\$12,533	\$3,745	235
Total (\$/boe)	\$0.47	\$0.10	370	\$0.68	\$0.32	113

Pursuant to the Company’s 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 39.0 million stock options (“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.

Stock-based compensation expense related to Stock Options, RSUs, PSUs, RIAs and PIAs for the three and nine months ended September 30, 2023, were higher compared to the same periods in 2022 primarily due to an increased number of equity-settled and cash-settled grants, due to increased staffing associated with the growth of the business.

During the three months ended September 30, 2023, the Company issued 0.3 million share units and 0.1 million incentive awards compared to 0.13 million share units and 0.26 million incentive awards during the same period in 2022.

During the nine months ended September 30, 2023, the Company issued 3.6 million share units and 1.5 million incentive awards compared to 2.8 million share units and 1.7 million incentive awards during the same period in 2022.

## Finance Expense

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Interest and fees on SLL Facility	<b>\$13,240</b>	\$4,591	188	<b>\$31,220</b>	\$14,456	116
Interest and fees on Term Facility	<b>4,632</b>	–	–	<b>15,540</b>	–	–
Interest and fees on SL Notes	<b>6,201</b>	4,102	51	<b>18,423</b>	10,121	82
Interest on DAP Notes	<b>2,271</b>	–	–	<b>8,919</b>	–	–
Other interest	<b>(5)</b>	–	–	<b>2,856</b>	–	–
Total interest expense	<b>26,339</b>	8,693	203	<b>76,958</b>	24,577	213
Interest on lease liabilities	<b>199</b>	185	8	<b>540</b>	564	(4)
Accretion on government loan and Facilities acquisition payments	<b>458</b>	96	377	<b>1,192</b>	282	323
Unrealized loss (gain) on foreign exchange	<b>6,723</b>	(10,500)	(164)	<b>1,430</b>	343	317
Unrealized loss (gain) on cross-currency swap	<b>(6,633)</b>	9,884	(167)	<b>(1,410)</b>	(292)	383
Accretion of decommissioning obligations	<b>1,865</b>	2,061	(10)	<b>6,104</b>	5,085	20
Total finance expense	<b>\$28,951</b>	\$10,419	178	<b>\$84,814</b>	\$30,559	178
Total finance expense(\$/boe)	<b>\$4.59</b>	\$2.60	77	<b>\$4.58</b>	\$2.61	75
Total interest expense(\$/boe)	<b>\$4.17</b>	\$2.17	92	<b>\$4.16</b>	\$2.10	98
Average drawings on credit facilities	<b>\$867,688</b>	\$100,921	760	<b>\$817,492</b>	\$262,856	211
Average drawings on SL Notes	<b>\$300,000</b>	\$225,850	33	<b>\$300,000</b>	\$183,684	63
Average drawings on DAP	<b>\$156,123</b>	–	–	<b>\$205,751</b>	–	–

Total finance expense for the three and nine months ended September 30, 2023, was higher compared to the same periods in 2022 due to higher interest rates and higher average drawings on the credit facilities which are primarily driven by the acquisitions throughout 2022. The Company is also incurring interest in 2023 on the SL Notes issued in the first and third quarters of 2022 and on the Deferred Acquisition Payment Notes (“DAP Notes”) issued in the fourth quarter of 2022. Canadian interest rates have increased in 2023 compared to the same period in 2022. Interest and fees on the SLL Facility and SL Notes includes the amortization of fees associated with these facilities (See Debt on page 18).

Cash interest expense per boe of \$4.16 was above the guidance range due to higher than forecasted interest rates for the period on the variable rate SLL facility.

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

(\$ thousands, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Depletion and depreciation	\$160,542	\$77,549	107	\$477,986	\$223,351	114
Amortization of undeveloped leases	780	845	(8)	2,331	1,884	24
<b>Total</b>	<b>\$161,322</b>	<b>\$78,394</b>	<b>106</b>	<b>\$480,317</b>	<b>\$225,235</b>	<b>113</b>
Depletion and depreciation (\$/boe)	\$25.44	\$19.39	31	\$25.84	\$19.08	35
Amortization (\$/boe)	0.12	0.21	(43)	0.13	0.16	(19)
<b>Total (\$/boe)</b>	<b>\$25.56</b>	<b>\$19.60</b>	<b>30</b>	<b>\$25.97</b>	<b>\$19.24</b>	<b>35</b>

For the three and nine months ended September 30, 2023, DD&A expense per boe was higher relative to the same periods in 2022. The increase was due to acquisitions that closed in 2022 that have a higher DD&A expense per boe than the corporate average.

On an absolute basis, DD&A expense was higher for the three and nine months ended September 30, 2023, due to higher production and higher DD&A expense per boe.

## Current Income Tax (Asset) Liability

(\$ thousands)	Nine months ended September 30, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$123,924	\$ –
Payments	(124,114)	–
Current income tax expense	80,241	75,849
Acquired income tax payable	–	48,075
Current income tax instalments	(96,049)	–
<b>Balance, end of the period</b>	<b>\$(15,998)</b>	<b>\$123,924</b>

For the three and nine months ended September 30, 2023, the Company recorded current income tax expense of \$35.5 million and \$80.2 million, respectively (September 30, 2022 – \$19.9 million and \$53.2 million, respectively).

For the three and nine months ended September 30, 2023, the Company recorded a deferred income tax recovery of \$31.8 million and \$64.2 million, respectively (September 30, 2022 – deferred income tax expense of \$20.3 million and \$39.0 million, respectively).

The higher-than-expected tax rate is primarily a result of the IAS 12 accounting treatment for deferred tax on Property plant and equipment (“PPE”) acquired in corporate acquisitions recognized as asset acquisitions under the Business Combinations optional fair value concentration test. The book value of PPE acquired on these corporate acquisitions was in excess of the tax pools acquired. As the excess book value of these assets acquired in corporate acquisitions recognized as asset acquisitions are depreciated, no deferred tax recovery is recognized on these assets which results in a higher effective tax rate. This is more evident in Q1/23 given the relative size of this item compared to net income.

## Adjusted Funds Flow and Net Income

(\$ thousands, except per share amounts)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Cash flow from operating activities	<b>\$199,756</b>	\$229,927	(13)	<b>\$415,645</b>	\$577,488	(28)
Current income tax expense	<b>(35,482)</b>	(19,894)	78	<b>(80,241)</b>	(53,236)	51
Income tax paid	<b>50,794</b>	–	–	<b>220,163</b>	–	–
Interest expense, excluding fees	<b>(27,544)</b>	–	–	<b>(75,433)</b>	–	–
Interest paid	<b>20,607</b>	–	–	<b>65,864</b>	–	–
Decommissioning expenditures	<b>3,583</b>	2,951	21	<b>4,768</b>	5,429	(12)
Changes in non-cash working capital	<b>43,485</b>	(35,150)	(224)	<b>18,957</b>	634	2,890
Adjusted funds flow <sup>(1)</sup>	<b>\$255,199</b>	\$177,834	44	<b>\$569,723</b>	\$530,315	7
Per share - basic <sup>(2)</sup>	<b>\$0.46</b>	\$0.40	15	<b>\$1.02</b>	\$1.23	(17)
Per share - diluted <sup>(2)</sup>	<b>\$0.46</b>	\$0.40	15	<b>\$1.02</b>	\$1.22	(16)
Net income	<b>\$8,634</b>	\$124,793	(93)	<b>\$36,874</b>	\$294,757	(87)
Per share - basic	<b>\$0.02</b>	\$0.28	(93)	<b>\$0.07</b>	\$0.68	(90)
Per share - diluted	<b>\$0.02</b>	\$0.28	(93)	<b>\$0.07</b>	\$0.68	(90)

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

<sup>(2)</sup> Supplemental Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

Cash flow from operating activities for the three and nine months ended September 30, 2023 was lower compared to the same periods in 2022 primarily due to lower commodity prices, the disposition of non-core Viking oil CGU assets in Q3/22, higher interest expense, higher current income tax expense and higher production and transportation costs, partially offset by an increase in revenue resulting from additional production due to acquisitions completed in 2022.

Adjusted funds flow (see “Non-IFRS Financial Measures”) for the three and nine months ended September 30, 2023 was higher compared to the same periods in 2022 for the reasons above. Adjusted funds flow increased period over period while cash flow from operating activities decreased primarily due to 2022 taxes paid in 2023 which lowered 2023 cash flow from operating activities.

The Company recorded net income of \$8.6 million (\$0.02 per share basic and diluted) and \$36.9 million (\$0.07 per share basic and diluted) during the three and nine months ended September 30, 2023 compared to net income of \$124.8 million (\$0.28 per share basic and diluted) and \$294.8 million (\$0.68 per share basic and diluted) in the same periods in 2022. Net income was reduced by \$97.7 million for the three and nine months ended September 30, 2023 due to a loss on assets held for sale.

## Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

(\$ thousands)	Three months ended September 30,			Nine months ended September 30,		
	2023	2022	% change	2023	2022	% change
Drilling, completion and equipping	\$85,660	\$76,292	12	\$262,117	\$232,203	13
Facilities	36,157	15,475	134	116,665	43,047	171
Land, seismic and other	942	6,684	(86)	9,970	58,051	(83)
Exploration and development expenditures	\$122,759	\$98,451	25	\$388,752	\$333,301	17
Property acquisitions	800	–	–	15,887	–	–
Proceeds from dispositions	(38,987)	(39,498)	(1)	(41,438)	(54,980)	(25)

<sup>(1)</sup> Includes cash consideration.

During the third quarter of 2023, the Company drilled, completed and equipped 41 (40.3 net) Clearwater oil wells and one (1.0 net) Charlie Lake oil well.

For the nine months ended September 30, 2023, the Company drilled, completed and equipped 93 (91.6 net) Clearwater oil wells and 14 (13.8 net) Charlie Lake oil wells.

For the three and nine months ended September 30, 2023 approximately \$10 million and \$50 million, respectively, of facility expenditures were related to the Company's drilling program and approximately \$25 million and \$65 million, respectively, of facility expenditures were related to major infrastructure projects including pipeline installations related to the Nipisi gas conservation program, construction of a gas plant in the Wembley area and the construction of an oil treating and water injection facility in the Nipisi area.

## Acquisitions and Dispositions

On January 6, 2023 the Company acquired assets in the Charlie Lake oil CGU for cash consideration of approximately \$2.9 million. On May 31, 2023 the Company acquired infrastructure assets in the Clearwater oil CGU for cash consideration of \$11.0 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisitions which resulted in the acquisitions being accounted for as asset acquisitions. As such the purchase prices of the minor acquisitions were allocated to the identifiable assets and liabilities based on their relative fair values at the date of the acquisitions.

On July 31, 2023 the Company disposed of a gross overriding royalty ("GORR") on select portions of its Clearwater and Charlie Lake oil properties and sold a working interest in two Wembley facilities, including its newly constructed gas plant, for proceeds of \$39.5 million. The dispositions resulted in a gain of \$4.4 million.

For the three and nine months ended September 30, 2023 the Company executed further minor acquisitions in the Clearwater oil CGU for approximately \$0.8 million and \$2.0 million, respectively.

For the nine months ended September 30, 2023 the Company disposed of non-core properties for proceeds of \$3.0 million. The dispositions resulted in a gain of \$2.3 million.

## Assets Held For Sale

On October 19, 2023, the Company entered into a purchase and sale agreement for the disposition of non-core Cardium oil assets for \$123.0 million in cash. As at September 30, 2023, the Company determined the closing was highly probable of occurring and the Cardium assets were reclassified to assets held for sale. After classifying the assets as held for sale, the Company recorded an impairment loss of \$97.7 million based on the expected net consideration to be received. A component of the impairment is due to the IFRS carrying value of the assets being before tax while the fair value of the assets was agreed with the buyer on an after-tax basis.

Closing of the transaction is expected to occur on or about November 3, 2023, subject to customary closing considerations. The net asset value of \$100.2 million reflects estimated closing adjustments including transaction costs, net operating income from the effective date and the payout of a facility rental agreement.

## Share Capital

(\$ thousands)	September 30, 2023		December 31, 2022	
	Number	Amount	Number	Amount
Balance, opening	556,440,901	\$1,879,250	406,938,099	\$1,242,392
Issue of common shares - cash	–	–	38,334,100	143,753
Issue of common shares - acquisitions	–	–	115,575,033	515,402
Issue of common shares - Option, RSU and PSU exercise	1,502,143	–	3,485,469	–
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	(1,235,050)	–	(3,529,100)	–
Share issue costs, net of tax (2023 - \$nil; 2022 - \$1,576)	–	–	–	(5,276)
Balance, ending	556,707,994	\$1,879,250	556,440,901	\$1,879,250

(thousands)	October 25, 2023	September 30, 2023	December 31, 2022
Common shares outstanding	556,715	556,708	556,441
Common shares held in treasury	226	233	500
Options outstanding - equity-settled	1,218	1,218	1,378
RSUs outstanding - equity-settled	4,345	4,352	3,430
PSUs outstanding - equity-settled	2,430	2,430	1,968

## Liquidity and Capital Resources

(\$ thousands)	September 30, 2023	December 31, 2022
Working capital deficiency (surplus) <sup>(1)</sup>	<b>\$(21,975)</b>	\$161,185
Note receivable	<b>(20,000)</b>	(20,000)
Credit facilities	<b>848,586</b>	650,848
SL Notes	<b>289,704</b>	287,691
DAP Notes	<b>106,667</b>	256,667
Assets held for sale, net <sup>(2)</sup>	<b>(100,208)</b>	–
Government loan and Facilities acquisition payments	<b>25,256</b>	20,179
Net debt <sup>(1)</sup>	<b>\$1,128,030</b>	\$1,356,570
Quarterly adjusted funds flow <sup>(1)</sup>	<b>\$255,199</b>	\$196,746
Annualized factor	<b>4</b>	4
Annualized adjusted funds flow <sup>(1)</sup>	<b>\$1,020,796</b>	\$786,984
Net debt to annualized adjusted funds flow <sup>(1)</sup>	<b>1.1x</b>	1.7x

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

<sup>(2)</sup> Assets held for sale, net, as defined in “Net Debt and Working Capital Deficiency (Surplus)” in the “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 facilities to fund its capital requirements, return of capital and provide liquidity.

Tamarack’s net debt, including working capital surplus (see “Capital Management Measures”), totaled \$1,128.0 million as at September 30, 2023. This compares to the Company’s net debt of \$286.8 million as at September 30, 2022 and \$1,356.6 million as at December 31, 2022. Tamarack’s Q3 2023 net debt to annualized adjusted funds flow ratio (see “Capital Management Measures”) was 1.1 times.

The Company’s \$122.8 million investment in capital additions, excluding acquisitions and dispositions, during Q3 2023 was fully funded by Tamarack’s adjusted funds flow (see “Capital Management Measures”) of \$255.2 million. The Q3 2023 decrease in the Company’s net debt of \$228.5 million as compared to December 31, 2022 was primarily due to free funds flow, changes in working capital, proceeds from Q3 2023 dispositions and the Assets held for sale, net, related to the Cardium oil CGU assets.

The Company believes that increased available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack’s 2023 development capital program, dividend payments and DAP Notes payments required in 2023 and 2024.

Pursuant to the Company’s approved normal course issuer bid (“NCIB”), the Company is permitted to purchase up to 27.8 million Common Shares over a period of 12 months commencing on January 19, 2023. During the three and nine months ended September 30, 2023, the Company did not purchase or cancel any Common Shares.

During the three and nine months ended September 30, 2023, the Company declared \$20.9 million and \$62.6 million, respectively, related to its monthly cash dividends on common shares of \$0.0125 per share and has accrued a dividend payable of \$7.0 million for the dividend declared on September 15, 2023.

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

## Debt

(\$ thousands)	September 30, 2023	December 31, 2022
Current Debt		
Credit Facilities		
Term Facility	<b>\$25,000</b>	\$65,000
DAP Notes	<b>106,667</b>	200,000
	<b>\$131,667</b>	\$265,000
Long-term Debt		
Credit Facilities		
SLL Facility	<b>\$648,586</b>	\$415,848
Term Facility	<b>175,000</b>	170,000
Credit Facilities total	<b>\$823,586</b>	\$585,848
SL Notes	<b>289,704</b>	287,691
DAP Notes	<b>–</b>	56,667
	<b>\$1,113,290</b>	\$930,206
<b>Total Debt</b>	<b>\$1,244,957</b>	<b>\$1,195,206</b>

<sup>(1)</sup> Debt amounts above are net of unamortized fees. Debt amounts in the “Commitments” section of this MD&A are principal outstanding.

### 1) Credit Facilities:

On October 13, 2022 the Company established a new three-year covenant-based Sustainability-Linked Lending Facility (“SLL Facility”) with a corresponding two-year secured amortizing term-loan (“Term Facility”). The SLL Facility and the Term Facility collectively constitute a “Syndicated Facility”. On May 10, 2023 the Syndicated Facility was amended including: an SLL Facility increase to \$875.0 million from \$700.0 million; extension of maturity on the SLL Facility from October 2025 to May 2026; and a decrease of the Term Facility to \$200.0 million for a revised total Syndicated Facility capacity of \$1,075.0 million. The Syndicated Facility is secured by a \$2.5 billion debenture with fixed coverage over all the assets of the Company. The SLL 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. The Term Facility bears interest at the applicable rate for the borrowing employed plus a fixed credit margin.

As the Syndicated 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 Syndicated Facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower.

#### SLL Facility:

The SLL Facility contains commercial covenants and sustainability adjustments in addition to financial covenants detailed below.

A total of \$655.8 million was drawn as of September 30, 2023 with a carrying value of \$648.6 million, net of fees to be amortized (December 31, 2022 – \$415.8 million drawn). In addition, \$5.4 million of the SLL Facility was reserved through issued and outstanding letters of credit. The interest rate applicable to the drawn amounts as of this date was 7.46% (December 31, 2022 – 6.21%). There are no mandatory principal repayments required prior to maturity.

## Term Facility:

The Term Facility is a covenant-based, non-revolving facility with a maturity date of October 13, 2024, and may be extended for a single 12-month term at the request of the borrower and the discretion of the lenders. In conjunction with the SLL Facility amendment, the Term Facility was amended to replace quarterly amortization payments with annual payments. Annual payments will commence in Q1 2024 in an amount equal to fifty percent (50%) of Excess Cash Flow as defined by the Syndicated Facility agreement. A component of proceeds from material dispositions will also be applied to the Term Facility. The Company previously made a quarterly amortization payment equal to \$25.0 million in Q4 2022.

A total of \$200.0 million was drawn as of September 30, 2023 (December 31, 2022 – \$235.0 million). The average interest rate applicable to the drawn amounts as of this date was 9.12% (December 31, 2022 – 8.38%).

## Financial Covenants:

The following table summarizes the financial covenants applicable to the Syndicated Facility and Term Facility at September 30, 2023:

Covenant Description	Position as at September 30, 2023	Covenant <sup>(5)</sup>
Total Debt <sup>(1)</sup> to EBITDA <sup>(2)</sup> Ratio	1.3:1.0	<3.0:1.0
Senior Debt <sup>(3)</sup> to EBITDA <sup>(2)</sup> Ratio	0.9:1.0	<2.5:1.0
Debt Service Coverage <sup>(4)</sup> Ratio	3.1:1.0	>1.5:1.0

<sup>(1)</sup> "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 of \$5.4 million outstanding as at September 30, 2023 and including indebtedness under the deferred acquisition notes issued on closing of the Delatstream acquisition.

<sup>(2)</sup> "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.

<sup>(3)</sup> "Senior Debt" is calculated in accordance with the credit facility agreements as Total Debt minus the SL Notes and permitted junior debt, including the Deferred Acquisition Payment Notes.

<sup>(4)</sup> "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.

<sup>(5)</sup> Covenants in effect while the Term Facility and Deferred Acquisition Payment 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.

## 2) SL Notes:

During 2022, the Company issued \$300.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 ("SL Notes"). The SL Notes were issued 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.

As at September 30, 2023 the carrying value of the SL Notes of \$289.7 million was net of \$10.3 million in discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at September 30, 2023 there was \$300.0 million principal outstanding on the SL Notes (December 31, 2022 – \$300.0 million). The next coupon payment is November 10, 2023, in the amount of \$10.9 million.

## 3) Deferred Acquisition Payment ("DAP") Notes:

On October 13, 2022, the Company issued \$300.0 million aggregate principal amount of DAP Notes. There are no financial covenants governing the DAP Notes. The DAP Notes were issued under a trust indenture and are unsecured and payable in cash quarterly over an 18-month period in an amount equal to the lesser of \$50.0 million and the aggregate principal amount of all outstanding notes.

The Company made its scheduled principal payment of \$50.0 million during the quarter. The Company paid \$2.3 million, concurrently, related to interest incurred during the third quarter. Interest on the DAP Notes is incurred at 5.75% per annum and is paid quarterly in arrears. The next payment is scheduled for the end of Q4 2023.

The aggregate outstanding principal of the DAP Notes is approximately \$106.7 million (December 31, 2022 – \$256.7 million).

## Commitments

The following table summarizes the Company's commitments as at September 30, 2023:

(\$ thousands)	2023	2024	2025	2026	2027+
Credit facilities <sup>(1)</sup>	–	200,000	–	655,827	–
SL Notes <sup>(2)</sup>	–	–	–	–	300,000
Interest on SL Notes <sup>(2)</sup>	10,875	21,750	21,750	21,750	10,875
DAP Notes <sup>(3)</sup>	50,000	56,667	–	–	–
Interest on DAP Notes <sup>(3)</sup>	1,546	826	–	–	–
Lease obligations	2,577	3,332	2,610	410	187
Government loan <sup>(4)</sup>	–	–	1,939	6,966	15,573
Take or pay commitments <sup>(5)</sup>	6,638	17,863	18,296	16,266	50,349
Processing commitments <sup>(6)</sup>	2,786	4,692	7,473	7,473	52,884
Gas transportation <sup>(7)</sup>	806	2,680	1,292	172	32
<b>Total</b>	<b>75,228</b>	<b>307,810</b>	<b>53,360</b>	<b>708,864</b>	<b>429,900</b>

<sup>(1)</sup> Term Facility matures on October 13, 2024 with annual amortization payments. SLL Facility matures on May 10, 2026 with no mandatory principal repayments prior to maturity. Excludes interest on SLL Facility as interest payments fluctuate based on floating rates of interest and changes in the outstanding balance.

<sup>(2)</sup> Principal amount of the SL Notes. SL Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

<sup>(3)</sup> Principal amount of the DAP Notes. DAP Notes bear a coupon rate of 5.75%, payable quarterly.

<sup>(4)</sup> Relates to the scheduled payments on the repayable government loan funding received from the Government of Canada under the terms of the ERF agreements.

<sup>(5)</sup> Pipeline commitments to deliver crude oil and/or crude oil and condensate for various volumes ranging from minimums of 129 m3/d to 1,589 m3/d at various tariffs ranging from \$9.00/m3 to \$25.22/m3 which expire between December 31, 2023 and December 31, 2030. Certain of these pipeline commitments escalate at 2% per annum.

<sup>(6)</sup> Processing commitments to guarantee firm processing capacity in various facilities.

<sup>(7)</sup> Gas transportation costs on long term firm contracts which are in various locations at variable rates.

## 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 2023 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 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 June 26, 2023, the ISSB issued *IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information"* and *IFRS S2 "Climate-related Disclosures"*. *IFRS S1* and *IFRS S2* are effective for annual reporting periods beginning on or after January 1, 2024. The sustainability standards as issued by the ISSB provide for transition relief in *IFRS S1* that allow a reporting entity to report only on climate-related risks and opportunities, as set out in *IFRS S2*, in the first year of reporting under the sustainability standards.

The Canadian Securities Administrators (“CSA”) are responsible for determining the reporting requirements for public companies in Canada and are responsible for decisions related to the adoption of the sustainability disclosure standards, including the effective annual reporting dates. The CSA issued proposed National Instrument (“NI 51-107 – *Disclosure of Climate-related Matters*”) in October 2021. The CSA has indicated it will consider the ISSB sustainability standards and developments in the United States in its decisions related to developing climate-related disclosure requirements for reporting issuers in Canada. The CSA will involve the Canadian Sustainability Standards Board (“CSSB”) for their combined review of the ISSB issued sustainability standards for their suitability for adoption in Canada. Until such time as the CSA and CSSB make decisions on sustainability standard adoption in Canada, there is no requirement for public companies in Canada to adopt the sustainability standards. The Company is actively evaluating the potential effects of the ISSB issued sustainability standards; however, at this time, the Company is not able to determine the impact on future financial statements, nor the potential costs to comply with these sustainability standards. There were no developments in Q3 2023.

## Sustainability

Tamarack is committed to the continued advancement of our ESG practices as outlined in our 2023 Sustainability Report released on June 29, 2023. This report provides details on the Company’s approach to sustainability, including our commitments to GHG emissions management and to continued Indigenous and community partnerships in the areas where we operate. In addition, the report highlights specific, measurable goals and targets related to key focus areas set by the Company.

Based on the Company’s commitment and approach to sustainability, the Company amended its revolving bank facility to a Sustainability-Linked Lending Facility (“SLL Facility”) in late 2021 which incorporates sustainability-linked interest rate terms (see Debt on page 18). In addition, the Company issued \$300.0 million of 7.25% senior unsecured sustainability-linked notes (“SL Notes”) during 2022, which are due May 10, 2027 (see Debt on page 18).

## Contingency

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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

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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

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AECO	Alberta Energy Company benchmark for natural gas
Bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
mmbtu/d	one million British thermal units per day
MSW	mixed sweet blend, the benchmark for conventionally produced light sweet crude oil in Western Canada
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
WCS	Western Canadian Select, the benchmark for both conventionally produced and oilsands produced heavy sour crude oil in Western Canada
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

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

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This document contains the terms “net production expenses”, “revenue, net of blending expense”, “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”, “capital expenditures” 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, deducting current income tax expense and interest expense excluding fees, adding back income tax paid, interest paid, expenditures on decommissioning obligations and transaction costs and deducting or adding back changes in non-cash working capital, as required. Management believes adjusting for estimated current income taxes and interest in the period expensed 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 supplemental financial measure. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a supplemental financial measure. 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, Revenue, net of blending expense, 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, revenue, net of blending expense, 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 income. 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. Blending expense includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In this MD&A, blending expense is recognized as a reduction to heavy oil revenues, whereas blending expense is reported as an expense in the financial statements. Operating netback equals total petroleum and natural gas sales (net of blending), 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 SL Notes plus DAP Notes plus Government loan plus Facilities acquisition payments less Note receivable plus working capital surplus or deficiency, less Assets held for sale, net of Liabilities associated with assets held for sale, excluding the current portion of 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, 2023	December 31, 2022
Accounts payable and accrued liabilities	<b>\$211,157</b>	\$220,568
Current income tax (asset) liability	<b>(15,998)</b>	123,924
Cross currency swap (asset) liability	<b>(657)</b>	753
Accounts receivable	<b>(209,320)</b>	(177,218)
Prepaid expenses and deposits	<b>(7,157)</b>	(6,842)
Working capital deficiency (surplus)	<b>\$(21,975)</b>	\$161,185
Note receivable	<b>(20,000)</b>	(20,000)
Credit facilities	<b>848,586</b>	650,848
SL Notes	<b>289,704</b>	287,691
DAP Notes	<b>106,667</b>	256,667
Assets held for sale, net	<b>(100,208)</b>	-
Government loan and Facilities acquisition payments	<b>25,256</b>	20,179
<b>Net debt</b>	<b>1,128,030</b>	1,356,570

**(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 17 in the section titled "Liquidity and Capital Resources".

**(e) Free Funds Flow and Capital Expenditures (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. Capital expenditures is calculated as property, plant and equipment additions (net of government assistance) plus exploration and evaluation additions. 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.

	Three months ended September 30,		Nine months ended September 30,	
	2023	2022	2023	2022
Adjusted funds flow	<b>\$255,199</b>	\$177,834	<b>\$569,723</b>	\$530,315
Less: Property, plant and equipment expenditures <sup>(1)</sup>	<b>122,714</b>	96,420	<b>381,650</b>	285,474
Exploration and evaluation expenditures	<b>45</b>	2,031	<b>7,102</b>	47,827
Capital expenditures	<b>122,759</b>	98,451	<b>388,752</b>	333,301
Free funds flow	<b>\$132,440</b>	\$79,383	<b>\$180,971</b>	\$197,014

<sup>(1)</sup> Includes government assistance of \$nil and \$2.7 million for the three and nine months ended September 30, 2023, respectively, and \$nil and \$4.4 million for the same periods in 2022.

## Selected Quarterly Information

Three months ended	Sept. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2022	Sept. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021
<b>Sales volumes</b>								
Natural gas (mcf/d)	72,597	68,027	74,293	68,355	62,428	67,195	70,989	74,291
Oil and NGL (bbls/d)	56,497	55,400	55,556	52,951	33,071	32,578	29,503	28,002
Average boe/d (6:1)	68,597	66,738	67,938	64,344	43,476	43,777	41,335	40,384
<b>Product prices</b>								
Natural gas (\$/mcf)	2.60	2.39	3.50	4.89	6.27	7.81	5.70	5.09
Oil and NGL (\$/bbl)	94.07	76.24	71.03	80.38	95.93	121.17	98.61	80.55
Oil equivalent (\$/boe)	80.24	65.72	61.91	71.34	81.98	102.16	80.17	65.21
<i>(000s, except per share amounts)</i>								
<b>Financial results</b>								
Gross revenues	506,365	399,155	378,546	422,313	327,910	406,971	298,254	242,288
Cash flow from operating activities	199,756	156,265	59,624	227,889	229,927	214,708	132,853	118,647
Adjusted funds flow <sup>(2)</sup>	255,199	157,253	157,271	196,746	177,834	203,622	166,581	124,080
Per share – basic <sup>(3)</sup>	0.46	0.28	0.28	0.36	0.40	0.47	0.40	0.31
Per share – diluted <sup>(3)</sup>	0.46	0.28	0.28	0.36	0.40	0.46	0.39	0.30
Net income	8,634	25,735	2,505	50,441	124,793	143,507	26,457	140,448
Per share – basic	0.02	0.05	–	0.09	0.28	0.33	0.06	0.35
Per share – diluted	0.02	0.05	–	0.09	0.28	0.33	0.06	0.34
Operating netback <sup>(4)</sup>	326,408	222,712	208,955	250,087	207,575	239,502	180,013	136,089
Capital expenditures <sup>(2)</sup>	122,759	117,831	148,162	125,276	98,451	109,483	125,367	41,672
Acquisitions <sup>(1)</sup>	800	12,148	2,939	1,447,973	1,365	112,175	224,270	22,593
Dispositions <sup>(1)</sup>	(38,987)	(2,271)	(180)	(21,873)	(59,498)	(15,482)	–	(74)
Total assets	4,443,837	4,559,903	4,593,760	4,619,701	2,839,146	2,829,984	2,648,093	2,328,153
Net debt <sup>(2)</sup>	1,128,030	1,373,620	1,374,068	1,356,570	286,762	470,563	556,374	463,284
Credit facilities (cash)	848,586	883,927	791,663	650,848	(97,509)	324,761	325,899	477,437
SL Notes	289,704	288,987	288,388	287,691	287,379	195,086	195,096	–
DAP Notes	106,667	156,667	206,667	256,667	–	–	–	–
Dividends declared per share	0.0375	0.0375	0.0375	0.0350	0.0300	0.0266	0.0249	–
Decommissioning obligations	166,868	266,898	265,374	264,988	237,813	238,768	270,458	284,472

<sup>(1)</sup> Includes cash and non-cash consideration.

<sup>(2)</sup> Capital Management Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

<sup>(3)</sup> Supplemental Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

<sup>(4)</sup> Non-IFRS Financial 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 flow from 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 October 13, 2022, Tamarack closed the acquisition of Clearwater area properties. The assets include approximately 19,500 boe/d of oil weighted assets, along with adding 184 net sections in the Clearwater oil play of Alberta for a total purchase consideration of approximately \$1.4 billion.
- 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.

## Critical Accounting Estimates

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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 forecasted 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 forecasted 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 oil and natural gas interests within PP&E. E&E assets and oil and natural gas interests 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 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. By their nature, these estimates of proved and probable oil and natural gas reserves 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 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, the estimate of unbooked oil and natural gas reserves and the discount rates. The estimate of proved and probable oil and natural gas reserves and the estimate of unbooked oil and natural gas reserves includes significant assumptions related to: forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs, forecasted future development costs and timing of development for the unbooked oil and natural gas reserves. The estimates of proved and probable oil and natural gas reserves and unbooked oil and natural gas reserves are prepared by the Company's external independent qualified reserves evaluator or internal qualified reserves evaluator.

## Disclosure Controls and Internal Controls over Financial Reporting

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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 changes to the Company's DCP and its ICFR were identified during the period ended September 30, 2023 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. As a result, the Company's DCP and ICFR were effective as at September 30, 2023.

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.

## Risks

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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. Tamarack is directly impacted by these risks:

- Volatility in commodity and petroleum product prices
- Inflation risk
- Environmental and climate change risk
- Financial risks
- Operational risks
- Regulatory risks

For additional information on the risks relating to Tamarack's business, see "Risk Factors" in Tamarack's Annual Information Form and "Business Risks" in Tamarack's Annual MD&A for the year ended December 31, 2022.

## Forward-Looking Statements

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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 completion and implementation of the Nipisi methane gas conservation project and the objectives thereof;
- the impacts on the Company of the military conflict between Russia and Ukraine;
- the Company's commitment to advancing ESG practices, managing GHG emissions and to continued Indigenous and community partnerships in the areas where it operates;
- the Company's continued consideration of the impact of climate change and possible upcoming related financial and operational challenges and implications with respect to the future of the Company;

- the Company's continued consideration of the potential impacts of the evolving global demand for carbon-based energy and global advancement of alternative energy sources;
- expectations surrounding ESG disclosure and reporting policies and standards imposed by the ISSB and the potential impacts thereof including IFRS S1 and IFRS S2 and proposed NI 51-107 and timing thereof (including expectations surrounding the CSA review process and intentions);
- expectations regarding the estimated recoverable amount of the Company's oil and natural gas properties, royalty rates as a percentage of revenue, and committed capital spending to develop the GORR Nipisi/Clearwater and Grande Prairie 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 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;
- purchases under the NCIB;
- the Company's plans in respect of returns of capital, including dividend and enhanced return programs;
- the Company's expectations surrounding its 2023 capital program and funding thereof, including in relation to the ability to satisfy its 2023 development capital program, dividend payments and DAP Notes payments required in 2023 and 2024 using available increased credit facilities combined with anticipated adjusted funds flow;
- the application of the terms of the Term Facility in respect of payments required thereunder and the timing thereof, including the annual payments commencing in Q1 2024;
- financial covenants applicable to the Syndicated Facility and Term Facility and the effect of outstanding Term Facility and DAP Notes (or lack thereof) in respect of the same;
- the maintained constructiveness of management's outlook with respect to WCS pricing despite persistent volatility;
- Tamarack's 2023 production guidance and ongoing assessments in respect of the same;
- the Company's commitment to ESG principles and Indigenous relationships, including as disclosed in its 2023 Sustainability Report;
- expectations surrounding the Company's 2023 capital guidance including in respect of funds flow generation over the short and long term, and anticipated focus on debt repayment and accelerating the timing of the enhanced return framework;
- the availability, size, terms, use and renewal of the SLL Facility, including the various lending vehicles used by the Company from time to time, and the terms thereof;
- the Company's ability to meet its obligations and commitments under the SL Notes;
- expectations relating to cash tax, tax pools, and deferred tax assets, including in respect of deferred income tax;
- 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;
- the Company's risk management activities;
- the Company's plans in respect to its employees including for its employees to address the continued development of new or established reservoirs on a go-forward basis using the same procedure as is used to address exploration risk and the effects thereof on mitigation of operation risk;
- expectations surrounding the Company's major infrastructure projects and anticipated benefits thereof, including with respect to performance of its Clearwater and Charlie Lake drilling programs;
- expectations surrounding management's continued flexibility in respect of its second half capital program (including in relation to fluctuating commodity prices and management's monitoring thereof);

- expectations regarding that identified changes to the Company's DCP and its ICFR during Q3 2023 are likely to materially affect the Company's internal controls over financial reporting;
- expectations regarding the merits and the outcome of ongoing litigation; and
- the Company's expectations regarding inflation and interest rates and the ability to manage such pressures.

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 including in respect of recent cuts to the group's production quotas (as announced by OPEC+ in April 2023);
- 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;
- Tamarack's ability to maintain financial flexibility; and
- the impact of inflation on costs and interest rates.

Without limitations of the foregoing, future dividend payments, if any, and the level thereof, are uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, commodity prices, free funds flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tamarack to pay dividends, and the frequency thereof, will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

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", "Risks";
- the material assumptions and observations described under the headings "Highlights for the Three and Nine Months Ended September 30, 2023", "Annual Guidance", "Q3 2023 Operational and Financial Highlights", "Production", "Petroleum and Natural Gas Sales", "Risk Management", "Royalties", "Net Production Expenses", "Transportation Expense", "Blending Expense", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expense", "Finance Expense", "Depletion, Depreciation and Amortization ("DD&A")", "Current Income Tax (Asset) Liability", "Adjusted Funds Flow and Net Income", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Acquisitions and Dispositions", "Assets Held for Sale", "Share Capital", "Liquidity and Capital Resources", "Debt", "Commitments", "Climate Change and Sustainability", "Contingency" and "Selected Quarterly Information";
- the risks relating to inclement and severe weather events and natural disasters, including fire, drought and flooding and corresponding effects, including in respect to safety, asset integrity, shutting in production, impact on production, maintaining 2023 guidance and resumption of operations;
- the risks with respect to unplanned third-party pipeline outages;
- 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;
- the evolving impact of the pandemics on the Company's business, financial condition and results of operations;
- uncertainty regarding the full impact of pandemics on global economies and oil demand and commodity prices;
- 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;
- third party inability to manage inflationary cost pressures;
- 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, 2022, which may be accessed on Tamarack's SEDAR+ profile [www.sedarplus.ca](http://www.sedarplus.ca) or on the Company's website at [www.tamarackvalley.ca](http://www.tamarackvalley.ca).

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's 2023 development capital program and plans regarding payment of 2023 dividends as well as DAP Notes and Term Facility amortization by using available increased credit facilities combined with anticipated adjusted funds flow, Tamarack's 2023 capital guidance and components thereof including prospective results of operations and production, expected capital expenditures (including in respect of Tamarack's capital E&D budget), annual average production, average oil & NGL weighting, expenses (including expected royalty rates, net production expenses, transportation expenses, G&A expenses, interest and taxes) and leasing expenditures, payout of wells, adjusted funds flow, free funds flow, net debt, capital requirements, return of capital, balance sheet strength, the Company's 2023 budget and associated targets, debt repayments, total returns and components thereof, decline rates, netback enhancement from blending, 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, 2023	December 31, 2022
<b>Assets</b>		
Current assets:		
Accounts receivable (note 5)	\$209,320	\$177,218
Prepaid expenses and deposits	7,157	6,842
Current income tax (note 9)	15,998	–
Fair value of financial instruments (note 3)	246	–
Cross-currency swap (note 11)	657	–
Assets held for sale (note 6 and 20)	175,518	–
	<b>408,896</b>	184,060
Note receivable	20,000	20,000
Fair value of financial instruments (note 3)	342	254
Property, plant and equipment (note 6)	3,971,021	4,370,025
Exploration and evaluation assets (note 7)	43,578	45,362
	<b>\$4,443,837</b>	\$4,619,701
<b>Liabilities and Shareholders' Equity</b>		
Current liabilities:		
Accounts payable and accrued liabilities	\$211,157	\$220,568
Debt (note 11)	131,667	265,000
Other liabilities (note 12 and 17)	5,530	6,424
Lease liabilities	3,781	4,479
Decommissioning obligations (note 8)	16,747	11,200
Cross-currency swap (note 11)	–	753
Current income tax (note 9)	–	123,924
Fair value of financial instruments (note 3)	24,782	10,594
Liabilities associated with assets held for sale (note 8 and 20)	75,310	–
	<b>468,974</b>	642,942
Debt (note 11)	1,113,290	930,206
Other liabilities (note 12 and 17)	30,339	25,746
Lease liabilities	6,936	6,360
Decommissioning obligations (note 8)	150,121	253,788
Deferred tax liability	533,219	597,420
	<b>2,302,879</b>	2,456,462
<b>Shareholders' Equity:</b>		
Share capital (note 14)	1,879,250	1,879,250
Treasury shares (note 14)	(848)	(2,451)
Contributed surplus	29,353	27,475
Retained earnings	233,203	258,965
	<b>2,140,958</b>	2,163,239
Subsequent events (note 20)		
Commitments (note 18)		
Contingency (note 19)		
	<b>\$4,443,837</b>	\$4,619,701

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, 2023 and 2022

(unaudited)(thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2023	2022	2023	2022
Revenue:				
Oil and natural gas (note 5)	\$506,365	\$327,910	\$1,284,066	\$1,033,135
Processing and other income	1,156	1,867	1,821	2,732
Royalties	(84,443)	(56,256)	(234,875)	(192,990)
Net revenue	423,078	273,521	1,051,012	842,877
Financial instrument contracts:				
Realized loss on financial instruments (note 3)	(15,922)	(11,615)	(34,892)	(63,916)
Unrealized gain (loss) on financial instruments (note 3)	(20,106)	47,820	(13,854)	32,064
Net revenue and gains (losses) on financial instruments	387,050	309,726	1,002,266	811,025
Expenses:				
Production	54,602	42,347	181,072	122,255
Transportation	26,034	11,511	74,062	29,143
Blending	112	–	2,319	–
General and administration	7,939	5,811	23,498	20,268
Stock-based compensation (note 16)	2,950	409	12,533	3,745
Finance (note 13)	28,951	10,419	84,814	30,559
Depletion, depreciation and amortization (note 6 and 7)	161,322	78,394	480,317	225,235
Loss (gain) on dispositions and assets held for sale (note 6 and 20)	92,840	(2,691)	90,911	(4,943)
Site rehabilitation program grant (note 8 and 17)	–	(1,494)	(174)	(2,198)
	374,750	144,706	949,352	424,064
Income before taxes	12,300	165,020	52,914	386,961
Taxes:				
Current income tax expense (note 9)	(35,482)	(19,894)	(80,241)	(53,236)
Deferred income tax recovery (expense)	31,816	(20,333)	64,201	(38,968)
	(3,666)	(40,227)	(16,040)	(92,204)
Net income and comprehensive income	\$8,634	\$124,793	\$36,874	\$294,757
Net income per share (note 15):				
Basic	\$ 0.02	\$ 0.28	\$ 0.07	\$ 0.68
Diluted	\$ 0.02	\$ 0.28	\$ 0.07	\$ 0.68

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, 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 treasury	(3,528)	–	(17,286)	–	–	(17,286)
Option, RSU and PSU exercise	3,446	–	14,703	(14,703)	–	–
Change to SBC liability	–	–	–	(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
Balance at January 1, 2023	556,441	\$1,879,250	\$(2,451)	\$27,475	\$258,965	\$2,163,239
Option, RSU and PSU exercise	1,502	–	5,760	(5,760)	–	–
Stock-based compensation	–	–	–	7,638	–	7,638
Option exercise proceeds	–	–	421	–	–	421
Purchase of common shares for treasury	(1,235)	–	(4,578)	–	–	(4,578)
Dividends	–	–	–	–	(62,636)	(62,636)
Net income	–	–	–	–	36,874	36,874
Balance at September 30, 2023	556,708	\$1,879,250	\$(848)	\$29,353	\$233,203	\$2,140,958

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, 2023 and 2022  
(unaudited)(thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2023	2022	2023	2022
Cash provided by (used in):				
Operating:				
Net income	\$8,634	\$124,793	\$36,874	\$294,757
Depletion, depreciation and amortization (note 6 and 7)	161,322	78,394	480,317	225,235
Stock-based compensation (note 16)	2,950	409	12,533	3,745
Stock-based compensation paid (note 16)	(244)	(196)	(9,772)	(6,651)
Loss (gain) on dispositions and assets held for sale (note 6 and 20)	92,840	(2,691)	90,911	(4,943)
Site rehabilitation program grant (note 8 and 17)	–	(1,494)	(174)	(2,198)
Finance (note 13)	28,951	10,419	84,814	30,559
Interest paid	(20,607)	(4,313)	(65,864)	(17,093)
Unrealized loss (gain) on financial instruments (note 3)	20,106	(47,820)	13,854	(32,064)
Income tax	3,666	40,227	16,040	92,204
Income tax paid (note 9)	(50,794)	–	(220,163)	–
Decommissioning expenditures (note 8)	(3,583)	(2,951)	(4,768)	(5,429)
Changes in non-cash working capital (note 10)	(43,485)	35,150	(18,957)	(634)
Cash provided by operating activities	199,756	229,927	415,645	577,488
Financing:				
Change in SLL Facility (note 11)	(49,911)	(314,724)	221,680	(479,243)
Repayment of Term Facility (note 11)	–	–	(35,000)	–
Issuance of SL Notes, net (note 11)	–	92,024	–	286,654
Repayment of DAP Notes (note 11)	(50,000)	–	(150,000)	–
Proceeds from issuance of shares, net	–	137,341	–	137,341
Purchase of common shares for cancellation (note 14)	–	(12,782)	–	(18,598)
Purchase of common shares for treasury (note 14)	(78)	–	(4,578)	(17,286)
Proceeds from option exercises (note 16)	–	–	421	1,691
Repayment of lease liabilities	(1,155)	(964)	(3,347)	(2,817)
Dividends (note 14)	(20,886)	(8,787)	(62,636)	(31,001)
Changes in other liabilities (note 12 and 17)	(360)	226	(647)	2,928
Changes in non-cash working capital (note 10)	(287)	(4,417)	(19)	1,120
Cash used in financing activities	(122,677)	(112,083)	(34,126)	(119,211)
Investing:				
Property, plant and equipment additions (note 6)	(122,714)	(96,420)	(384,326)	(289,916)
Government assistance	–	–	–	4,442
Exploration and evaluation additions (note 7)	(45)	(2,031)	(7,102)	(47,827)
Acquisitions (note 6)	(800)	(1,365)	(15,887)	(149,389)
Proceeds from dispositions (note 6)	38,987	39,498	41,438	54,980
Changes in non-cash working capital (note 10)	7,493	39,983	(15,642)	66,942
Cash used in investing activities	(77,079)	(20,335)	(381,519)	(360,768)
Change in cash and cash equivalents	–	97,509	–	97,509
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	\$ –	\$97,509	\$ –	\$97,509

See accompanying notes to the condensed consolidated interim financial statements.

# TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

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## 1. Reporting entity:

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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 wholly owned subsidiary, 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 – 3<sup>rd</sup> Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 3300, 308 – 4<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 0H7.

## 2. Basis of preparation:

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### (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, 2022. 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, 2022. Certain prior period balances were reclassified to conform to current period presentation.

The condensed consolidated interim financial statements have been prepared on the historical cost basis except for certain derivative financial instruments (including cross-currency swaps) and share-based payment arrangements classified as cash-settled, which are measured at fair value, and share-based payment arrangements classified as equity-settled are measured at fair value at the grant date in accordance with IFRS 2.

These condensed consolidated interim financial statements are presented in Canadian dollars, which is the Company’s functional currency.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on October 25, 2023.

### (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 condensed consolidated 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, 2022.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

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### Significant accounting policies:

The accounting policies, critical accounting judgments and significant estimates used in the preparation of the December 31, 2022 annual consolidated financial statements have been applied in the preparation of these condensed consolidated interim financial statements.

### 3. Financial instruments and risk management:

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#### (a) Financial instruments:

The Company's financial assets and liabilities are comprised of Accounts receivable, Note receivable, Accounts payable and accrued liabilities, Current income tax, Fair value of financial instruments, Cross-currency swap, Other liabilities (includes Cash award incentive plan liability, Government loan liability, and Facilities acquisition payments), and Debt. The carrying value of the Note receivable and Debt (with the exception of SL Notes) approximates their fair value as they bear 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.

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 long-term, fixed price marketing contracts. The Company does not enter 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.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

All financial derivative contracts are measured and recognized 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, 2023 the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

### Crude Oil Derivatives:

	Q4 2023		Q1 2024		Q2 2024		Q3 2024		Q4 2024	
<b>WTI 2-way Collar</b>										
<b>Volume (bbls/d)</b>	<b>20,000</b>		<b>21,000</b>		<b>19,500</b>		<b>11,500</b>		<b>3,000</b>	
Average Put/Call	67.00	87.54	66.93	86.30	69.36	89.39	68.85	93.13	67.50	92.09
Premium (USD/bbl)	1.93		0.93		1.00		1.38		1.33	
<b>Volume (bbls/d)</b>	<b>850</b>		-		-		-		-	
Average Put/Call (CAD/bbl)	80.44	108.64	-	-	-	-	-	-	-	-
<b>WTI Fixed Price</b>										
<b>Volume (bbls/d)</b>	<b>200</b>		-		-		-		-	
Average Fixed Price (CAD/bbl)	91.75		-		-		-		-	
<b>MSW Differential</b>										
<b>Volume (bbls/d)</b>	<b>2,500</b>		<b>2,500</b>		<b>3,000</b>		<b>4,000</b>		<b>4,000</b>	
Average Fixed Price (USD/bbl)	(2.55)		(2.69)		(2.73)		(2.63)		(2.63)	
<b>WCS Differential</b>										
<b>Volume (bbls/d)</b>	<b>14,000</b>		<b>4,500</b>		<b>4,000</b>		<b>500</b>		<b>500</b>	
Average Fixed Price (USD/bbl)	(16.57)		(14.76)		(13.57)		(13.75)		(13.75)	
<b>Volume (bbls/d)</b>	<b>700</b>		-		-		-		-	
Average Fixed Price (CAD/bbl)	(19.29)		-		-		-		-	

### Natural Gas Derivatives:

	Summer 23 <sup>(1)</sup>		Sept/Oct 23		Winter 23/24 <sup>(2)</sup>		Summer 24 <sup>(1)</sup>	
<b>AECO – NYMEX Basis</b>								
<b>Volume (mmbtu/d)</b>	<b>17,500</b>		-		<b>25,000</b>		<b>2,500</b>	
Average Fixed Price (USD/mmbtu)	(1.87)		-		(1.10)		(1.11)	
<b>AECO 5A Swap</b>								
<b>Volume (GJ/d)</b>	-		<b>25,000</b>		-		<b>1,000</b>	
Average Fixed Price (CAD/GJ)	-		2.36		-		2.80	
<b>NYMEX Collar</b>								
<b>Volume (mmbtu/d)</b>	<b>17,500</b>		-		<b>25,000</b>		<b>2,500</b>	
Average Put/Call (USD/mmbtu)	4.56	6.98	-	-	3.08	4.28	3.05	3.50

<sup>(1)</sup> Summer runs from April 1 to October 31 of the given year.

<sup>(2)</sup> Winter runs from November 1 to March 31 of the given year.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### Foreign Exchange Derivatives:

	Q4 2023		Q1 2024		Q2 2024		Q3 2024		Q4 2024	
<b>CAD/USD Collar</b>										
<b>Amount (USD/month)</b>	<b>\$12,000,000</b>		<b>\$3,000,000</b>		<b>\$3,000,000</b>		-		-	
Average Put/Call (CAD/USD)	1.3254	1.3909	1.3333	1.3885	1.3333	1.3885	-	-	-	-
<b>CAD/USD Variable Rate Collar</b>										
<b>Amount (USD/month)</b>	<b>\$11,500,000</b>		<b>\$18,500,000</b>		<b>\$18,500,000</b>		<b>\$6,000,000</b>		<b>\$6,000,000</b>	
Average Put/Call (CAD/USD) <sup>(1)</sup>	1.33	1.41	1.33	1.41	1.33	1.41	1.33	1.41	1.33	1.41
Knockout Rate (CAD/USD) <sup>(1)</sup>	1.36		1.36		1.36		1.36		1.36	
<b>CAD/USD Variable Rate Collar (Extendable Option)<sup>(2)</sup></b>										
<b>Amount (USD/month)</b>	<b>\$12,500,000</b>		<b>\$4,500,000</b>		<b>\$4,500,000</b>		<b>\$2,000,000</b>		<b>\$2,000,000</b>	
Average Put/Call (CAD/USD) <sup>(1)</sup>	1.33	1.41	1.33	1.41	1.33	1.41	1.32	1.40	1.32	1.40
Knockout Rate (CAD/USD) <sup>(1)</sup>	1.36		1.36		1.36		1.38		1.38	
<b>CAD/USD Swap</b>										
<b>Amount (USD/month)</b>	<b>\$6,000,000</b>		<b>\$5,000,000</b>		<b>\$5,000,000</b>		<b>\$3,000,000</b>		<b>\$3,000,000</b>	
Average Fixed Price (CAD/USD)	1.3399		1.3539		1.3539		1.3553		1.3553	
<b>Put Deferred Premium</b>										
<b>Amount (USD/month)</b>	-		<b>\$3,000,000</b>		-		-		-	
Average Put (CAD/USD)	-		1.32		-		-		-	
Average Premium (CAD/USD)	-		0.01		-		-		-	

<sup>(1)</sup> If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.

<sup>(2)</sup> Includes an extension option at the end of the collar, at the counterparty's option, for an equivalent term at an average rate forward fixed price equal to the call.

### Interest Rate Derivatives:

	2023	2024
<b>CDOR Swap</b>		
<b>Amount (million CAD\$/year)</b>	<b>30.0</b>	<b>6.3</b>
Average Interest Rate	1.047%	1.045%

At September 30, 2023 Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of \$24,194 (December 31, 2022 - \$10,340 net liability) recorded on the balance sheet. The Company had an unrealized loss of \$20,106 and a realized loss of \$15,922 recorded in earnings for the three months ended September 30, 2023 (September 30, 2022 - \$47,820 unrealized gain and \$11,615 realized loss). The Company had an unrealized loss of \$13,854 and a realized loss of \$34,892 recorded in earnings for the nine months ended September 30, 2023 (September 30, 2022 - \$32,064 unrealized gain and \$63,916 realized loss).

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, 2023 the Company held no 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.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### 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, Note receivable, Debt, Other liabilities (excluding Cash award incentive plan) and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending or dividends to manage current and projected debt levels.

#### (a) Adjusted funds flow:

Adjusted funds flow is calculated by taking cash flow from operating activities, deducting current income tax expense and interest expense excluding fees, adding back income tax paid, interest paid, expenditures on decommissioning obligations and transaction costs and deducting or adding back changes in non-cash working capital, as required. 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.

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Cash flow from operating activities	\$199,756	\$229,927	\$415,645	\$577,488
Current income tax expense (note 9)	(35,482)	(19,894)	(80,241)	(53,236)
Income tax paid (note 9)	50,794	–	220,163	–
Interest expense, excluding fees	(27,544)	–	(75,433)	–
Interest paid	20,607	–	65,864	–
Decommissioning expenditures	3,583	2,951	4,768	5,429
Changes in non-cash working capital (note 10)	43,485	(35,150)	18,957	634
Adjusted funds flow	\$255,199	\$177,834	\$569,723	\$530,315

#### (b) Free funds flow and Capital expenditures:

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. Tamarack uses free funds flow as a key measure to measure liquidity and demonstrate the Company's ability to generate shareholder returns through debt repayment, share repurchases, payment of dividends, acquisitions, and other opportunities that build long-term shareholder value.

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Adjusted funds flow	\$255,199	\$177,834	\$569,723	\$530,315
Less: Property, plant and equipment expenditures <sup>(1)</sup>	122,714	96,420	381,650	285,474
Exploration and evaluation expenditures	45	2,031	7,102	47,827
Capital expenditures	122,759	98,451	388,752	333,301
Free funds flow	\$132,440	\$79,383	\$180,971	\$197,014

<sup>(1)</sup> Includes government assistance of \$nil and \$2.7 million for the three and nine months ended September 30, 2023, respectively, and \$nil and \$4.4 million for the same periods in 2022.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### (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 Debt plus Government loan liability plus Assets held for sale, net of Liabilities associated with assets held for sale, Facilities acquisition payments, less Note 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 Current income tax liability plus Cross-currency swap liability minus Current income tax asset 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, 2023 the Company's ratio of net debt to annualized third quarter adjusted funds flow was 1.1 to 1 (December 31, 2022 – 1.7 to 1). The Company believes that available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's development capital program, dividend payments and DAP Notes and Term Facility payments for the next 12 months.

	September 30, 2023	December 31, 2022
Accounts payable and accrued liabilities	\$211,157	\$220,568
Current income tax (asset) liability	(15,998)	123,924
Cross-currency swap liability (asset)	(657)	753
Accounts receivable	(209,320)	(177,218)
Prepaid expenses and deposits	(7,157)	(6,842)
Working capital deficiency (surplus)	\$(21,975)	\$161,185
Note receivable	(20,000)	(20,000)
Credit facilities	848,586	650,848
SL Notes	289,704	287,691
DAP Notes	106,667	256,667
Assets held for sale, net	(100,208)	–
Government loan and Facilities acquisition payments	25,256	20,179
Net debt	\$1,128,030	\$1,356,570
Quarterly adjusted funds flow	\$255,199	\$196,746
Annualized factor	4	4
Annualized adjusted funds flow	\$1,020,796	\$786,984
Net debt to annualized adjusted funds flow	1.1x	1.7x

Neither the Company nor its subsidiary are subject to externally imposed capital requirements.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### 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. As of September 30, 2023, the Company did not have any contracts for the sale of its future production beyond one year in term. Revenues are normally collected on the business day nearest the 25<sup>th</sup> day of the month following the sale.

The Company's revenues were primarily generated in its core areas: the Clearwater oil play in north-central Alberta; the Charlie Lake oil play in northwestern Alberta; the Cardium oil play in central Alberta and the Viking oil play in central and 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		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Light oil	\$168,379	\$167,023	\$450,757	\$569,281
Heavy oil	306,775	108,308	734,711	285,804
Natural gas	17,391	36,028	55,594	120,197
Natural gas liquids	13,820	16,551	43,004	57,853
Oil and natural gas revenues	\$506,365	\$327,910	\$1,284,066	\$1,033,135

Included in accounts receivable of \$209.3 million on September 30, 2023 was \$182.6 million (December 31, 2022 - \$130.8 million) of accrued production revenue.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### 6. Property, plant and equipment:

	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at December 31, 2021	\$3,391,539	\$5,615	\$3,397,154
Right-of-use assets	1,283	1,401	2,684
Acquisitions	2,200,479	377	2,200,856
Capital additions <sup>(1)</sup>	406,203	1,137	407,340
Decommissioning costs	(19,557)	–	(19,557)
Stock-based compensation	3,739	–	3,739
Transfer from exploration and evaluation assets (note 7)	6,559	–	6,559
Disposals	(143,973)	–	(143,973)
Balance at December 31, 2022	5,846,272	8,530	5,854,802
Right-of-use assets	–	3,225	3,225
Acquisitions	18,292	–	18,292
Capital additions <sup>(1)</sup>	380,163	1,487	381,650
Decommissioning costs	(20,150)	–	(20,150)
Stock-based compensation	3,497	–	3,497
Transfer to assets held for sale (note 20)	(768,178)	–	(768,178)
Transfer from exploration and evaluation assets (note 7)	6,555	–	6,555
Disposals	(91,541)	–	(91,541)
Balance at September 30, 2023	\$5,374,910	\$13,242	\$5,388,152
Accumulated depletion, depreciation and impairment:			
Balance at December 31, 2021	\$1,158,513	\$2,106	\$1,160,619
Depletion and depreciation	373,388	1,593	374,981
Disposals	(50,823)	–	(50,823)
Balance at December 31, 2022	1,481,078	3,699	1,484,777
Depletion and depreciation	476,615	1,371	477,986
Transfer to assets held for sale (note 20)	(494,934)	–	(494,934)
Disposals	(50,698)	–	(50,698)
Balance at September 30, 2023	\$1,412,061	\$5,070	\$1,417,131
Carrying amounts:			
At December 31, 2022	\$4,365,194	\$4,831	\$4,370,025
At September 30, 2023	\$3,962,849	\$8,172	\$3,971,021

<sup>(1)</sup> Includes government assistance of \$2.7 million and \$4.4 million as at September 30, 2023 and December 31, 2022, respectively.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

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### (a) Security:

At September 30, 2023 all of the Company's properties were pledged as security for the credit facilities (note 11).

### (b) Depletion and depreciation:

The calculation of depletion at September 30, 2023 includes estimated future development costs of \$1,573,243 (December 31, 2022 – \$1,589,050) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of \$100,698 (December 31, 2022 – \$99,420).

### (c) Impairment (reversal):

At September 30, 2023 assets held for sale in the Cardium oil CGU were revalued to fair value less cost to sell, resulting in a \$97.7 million impairment (note 20). At September 30, 2023 and 2022 there were no indicators of impairment identified on any of the Company's remaining CGUs within property, plant and equipment. No other impairment or reversal of impairment tests were performed.

### (d) Acquisitions and dispositions:

On January 6, 2023 the Company acquired assets in the Charlie Lake oil CGU for cash consideration of approximately \$2.9 million. On May 31, 2023 the Company acquired infrastructure assets in the Clearwater oil CGU for cash consideration of \$11.0 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisitions which resulted in the acquisitions being accounted for as asset acquisitions. As such the purchase prices of the minor acquisitions were allocated to the identifiable assets and liabilities based on their relative fair values at the date of the acquisitions.

On July 31, 2023 the Company disposed of a gross overriding royalty ("GORR") on select portions of its Clearwater and Charlie Lake oil properties and sold a working interest in two Wembley facilities, including its newly constructed gas plant, for proceeds of \$39.5 million. The dispositions resulted in a gain of \$4.4 million.

For the three and nine months ended September 30, 2023 the Company executed further minor acquisitions in the Clearwater oil CGU for approximately \$0.8 million and \$2.0 million, respectively.

For the three and nine months ended September 30, 2023 the Company disposed of non-core properties for proceeds of \$0.5 million and \$3.0 million, respectively. The dispositions resulted in a gain of \$0.4 million and \$2.3 million, respectively, for the three and nine months ended September 30, 2023.

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### (e) 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, 2021	\$8,041	\$1,700	\$9,741
Lease additions	1,283	1,401	2,684
Leases acquired	1,093	377	1,470
Depletion and depreciation	(2,765)	(1,002)	(3,767)
Balance at December 31, 2022	\$7,652	\$2,476	\$10,128
Lease additions	–	3,225	3,225
Depletion and depreciation	(2,412)	(814)	(3,226)
Balance at September 30, 2023	\$5,240	\$4,887	\$10,127

## 7. Exploration and evaluation assets:

	Total
Cost:	
Balance at December 31, 2021	\$26,168
Additions	51,237
Disposal	(3,007)
Transfer to property, plant and equipment (note 6)	(6,559)
Balance at December 31, 2022	67,839
Additions	7,102
Transfer to property, plant and equipment (note 6)	(6,555)
Balance at September 30, 2023	\$68,386
Accumulated amortization and impairment:	
Balance at December 31, 2021	\$22,360
Amortization	2,702
Disposal	(2,585)
Balance at December 31, 2022	22,477
Amortization	2,331
Balance at September 30, 2023	\$24,808
	Total
Carrying amounts:	
At December 31, 2022	\$45,362
At September 30, 2023	\$43,578

Exploration and evaluation additions for the nine months ended September 30, 2023 includes approximately \$6.5 million of bonus land payments and drilling and completion costs in the Greater Peavine Clearwater area.

At September 30, 2023 and 2022 there were no indicators of impairment identified on any of the Company's CGUs within exploration and evaluation assets. In addition, there was no impairment recorded as a result of the impairment assessment on the transfer of exploration and evaluation assets to property, plant and equipment for the three and nine months ended September 30, 2023.

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### 8. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately \$309.5 million, including liabilities associated with assets held for sale, at September 30, 2023 (December 31, 2022 – \$309.1 million), which is expected to be incurred between 2023 and 2050. A risk-free rate of 3.8% (December 31, 2022 – 3.3%) and an inflation rate of 1.8% (December 31, 2022 – 2.1%) have been used to calculate the present value of the decommissioning obligations at September 30, 2023 as presented in the table below:

	Nine months ended September 30, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$264,988	\$284,472
Liabilities incurred	7,003	7,701
Liabilities acquired	2,405	19,719
Change in estimates	(27,153)	(54,787)
Change in discount rate on acquisition	–	27,529
Expenditures	(4,768)	(7,976)
Site rehabilitation program grant (note 17)	(174)	(3,377)
Liabilities disposed (note 6)	(6,227)	(15,969)
Liabilities associated with assets held for sale (note 20)	(75,310)	–
Accretion (note 13)	6,104	7,676
Balance, end of the period	\$166,868	\$264,988

During the nine months ended September 30, 2023 approximately \$0.2 million was granted and paid through the Site Rehabilitation Program (“SRP”) and Accelerated Site Closure Program (“ASCP”) programs to pay service companies to complete abandonment and reclamation work (December 31, 2022 – \$3.4 million).

The change in estimates for the nine months ended September 30, 2023 resulted from decommissioning obligations being revalued using a risk-free rate of 3.8% and an inflation rate of 1.8% as opposed to a risk-free rate of 3.3% and an inflation rate of 2.1% used at December 31, 2022.

Timing of decommissioning obligation expenditures expected to be incurred are:

	As at September 30, 2023
Decommissioning obligations – Less than 1 year	\$16,747
Decommissioning obligations – Greater than 1 year	150,121
Total	\$166,868

### 9. Current income tax (asset) liability:

	Nine months ended September 30, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$123,924	\$ –
Payments	(124,114)	–
Current income tax expense	80,241	75,849
Acquired income tax payable	–	48,075
Current income tax instalments	(96,049)	–
Balance, end of the period	\$(15,998)	\$123,924

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### 10. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Source/(use) of cash:				
Accounts receivable	<b>\$(58,468)</b>	\$55,540	<b>\$(32,102)</b>	\$(32,929)
Prepaid expenses and deposits	<b>1,435</b>	509	<b>(315)</b>	(3,614)
Accounts payable and accrued liabilities	<b>18,124</b>	23,084	<b>(9,411)</b>	111,434
Interest payable	<b>2,632</b>	(3,648)	<b>–</b>	(5,860)
Government assistance receivable	<b>–</b>	–	<b>7,210</b>	–
Dividends payable	<b>(2)</b>	(4,769)	<b>–</b>	(4,769)
Working capital acquired	<b>–</b>	–	<b>–</b>	3,166
	<b>\$(36,279)</b>	\$70,716	<b>\$(34,618)</b>	\$67,428
Related to operating activities	<b>\$(43,485)</b>	\$35,150	<b>\$(18,957)</b>	\$(634)
Related to financing activities	<b>\$(287)</b>	\$(4,417)	<b>\$(19)</b>	\$1,120
Related to investing activities	<b>\$7,493</b>	\$39,983	<b>\$(15,642)</b>	\$66,942

### 11. Debt:

	September 30, 2023	December 31, 2022
Current Debt		
Credit Facilities		
Term Facility	<b>\$25,000</b>	\$65,000
DAP Notes	<b>106,667</b>	200,000
	<b>\$131,667</b>	\$265,000
Long-term Debt		
Credit Facilities		
SLL Facility	<b>\$648,586</b>	\$415,848
Term Facility	<b>175,000</b>	170,000
Credit Facilities total	<b>\$823,586</b>	\$585,848
SL Notes	<b>289,704</b>	287,691
DAP Notes	<b>–</b>	56,667
	<b>\$1,113,290</b>	\$930,206
Total Debt	<b>\$1,244,957</b>	\$1,195,206

<sup>(1)</sup> Debt amounts above are net of unamortized fees. Debt amounts in Note 18 are principal outstanding.

#### (a) Credit Facilities:

On October 13, 2022 the Company established a new three-year covenant-based Sustainability-Linked Lending Facility (“SLL Facility”) with a corresponding two-year secured amortizing term-loan (“Term Facility”). The SLL Facility and the Term Facility collectively constitute a “Syndicated Facility”. On May 10, 2023 the Syndicated Facility was amended including: an SLL Facility increase to \$875.0 million from \$700.0 million; extension of maturity on the SLL Facility from October 2025 to May 2026; and a decrease of the Term Facility to \$200.0 million for a revised total Syndicated Facility capacity of \$1,075.0 million. The Syndicated Facility is secured by a \$2.5 billion debenture with fixed coverage over all the assets of the Company. The SLL 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. The Term Facility bears interest at the applicable rate for the borrowing employed plus a fixed credit margin.

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As the Syndicated 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 Syndicated Facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower.

### SLL Facility:

The SLL Facility contains commercial covenants and sustainability adjustments in addition to financial covenants detailed below.

A total of \$655.8 million was drawn as of September 30, 2023 with a carrying value of \$648.6 million, net of fees to be amortized (December 31, 2022 – \$415.8 million). In addition, \$5.4 million of the SLL Facility was reserved through issued and outstanding letters of credit. The interest rate applicable to the drawn amounts as of this date was 7.46% (December 31, 2022 – 6.21%). There are no mandatory principal repayments required prior to maturity.

### Term Facility:

The Term Facility is a covenant-based, non-revolving facility with a maturity date of October 13, 2024, and may be extended for a single 12-month term at the request of the borrower and the discretion of the lenders. In conjunction with the SLL Facility amendment, the Term Facility was amended to replace quarterly amortization payments with annual payments. Annual payments will commence in Q1 2024 in an amount equal to fifty percent (50%) of Excess Cash Flow as defined by the Syndicated Facility agreement. A component of proceeds from material dispositions will also be applied to the Term Facility. The Company previously made a quarterly amortization payment equal to \$25.0 million in Q4 2022.

A total of \$200.0 million was drawn as of September 30, 2023 (December 31, 2022 – \$235.0 million). The average interest rate applicable to the drawn amounts as of this date was 9.12% (December 31, 2022 – 8.38%).

### Financial Covenants:

The following table summarizes the financial covenants applicable to the SLL Facility and Term Facility at September 30, 2023:

Covenant Description	Position as at September 30, 2023	Covenant <sup>(5)</sup>
Total Debt <sup>(1)</sup> to EBITDA <sup>(2)</sup> Ratio	1.3:1.0	<3.0:1.0
Senior Debt <sup>(3)</sup> to EBITDA <sup>(2)</sup> Ratio	0.9:1.0	<2.5:1.0
Debt Service Coverage <sup>(4)</sup> Ratio	3.1:1.0	>1.5:1.0

<sup>(1)</sup> "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 of \$5.4 million outstanding as at September 30, 2023 and including indebtedness under the deferred acquisition notes issued on closing of the Deltastream acquisition.

<sup>(2)</sup> "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.

<sup>(3)</sup> "Senior Debt" is calculated in accordance with the credit facility agreements as Total Debt minus the SL Notes and permitted junior debt, including the Deferred Acquisition Payment Notes.

<sup>(4)</sup> "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.

<sup>(5)</sup> Covenants in effect while the Term Facility and Deferred Acquisition Payment 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.

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### (b) SL Notes:

During 2022, the Company issued \$300.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 (“SL Notes”). The SL Notes were issued 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.

As at September 30, 2023 the carrying value of the SL Notes of approximately \$289.7 million was net of approximately \$10.3 million in discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at September 30, 2023 there was \$300.0 million principal outstanding on the SL Notes (December 31, 2022 – \$300.0 million). The next coupon payment is November 10, 2023, in the amount of approximately \$10.9 million.

As at September 30, 2023, the fair value of the Company’s SL notes was \$291.3 million (December 31, 2022 – \$285.0 million)

### (c) Deferred Acquisition Payment (“DAP”) Notes:

On October 13, 2022, the Company issued \$300.0 million aggregate principal amount of DAP Notes. There are no financial covenants governing the DAP Notes. The DAP Notes were issued under a trust indenture and are unsecured and payable in cash quarterly over an 18-month period in an amount equal to the lesser of \$50.0 million and the aggregate principal amount of all outstanding notes.

The Company made a scheduled principal payment of \$50.0 million during the quarter. The Company paid \$2.3 million, concurrently, related to interest incurred during the third quarter. Interest on the DAP Notes is incurred at 5.75% per annum and is paid quarterly in arrears. The next payment is scheduled for the end of Q4 2023.

The aggregate outstanding principal of the DAP Notes is approximately \$106.7 million (December 31, 2022 – \$256.7 million).

## 12. Other liabilities:

	September 30, 2023	December 31, 2022
Cash award incentive plan	\$5,530	\$6,424
Current other liabilities	\$5,530	\$6,424
Cash award incentive plan	\$5,083	\$5,567
Facilities acquisition payments	4,026	4,292
Government loan	21,230	15,887
Long-term other liabilities	\$30,339	\$25,746

### (a) Government loan:

On January 16, 2023 the Company entered into an agreement to receive an estimated \$7.8 million of additional funding through its methane conservation program. As at September 30, 2023 the Company has recorded a discounted liability of \$21.2 million of government assistance, which includes \$7.2 million recognized in the nine months ended September 30, 2023, that is repayable under the terms of the Federal Government of Canada Emissions Reduction Fund (“ERF”) agreements. The ERF agreements include scheduled repayments of approximately \$1.9 million on March 31, 2025, \$7.0 million on March 31, 2026, \$12.7 million on March 31, 2027 and a final payment of \$2.9 million on March 31, 2028. The repayable government loan funding will be interest-free based on the Company’s compliance with the terms and conditions of the ERF funding agreements and all repayments made in accordance with the above noted repayment schedule.

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### 13. Finance expense:

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Interest and fees on SLL Facility (note 11)	\$13,240	\$4,591	\$31,220	\$14,456
Interest and fees on Term Facility (note 11)	4,632	–	15,540	–
Interest and fees on SL Notes (note 11)	6,201	4,102	18,423	10,121
Interest on DAP Notes (note 11)	2,271	–	8,919	–
Interest on lease liabilities	199	185	540	564
Accretion on government loan and Facilities acquisition payments (note 12)	458	96	1,192	282
Other interest	(5)	–	2,856	–
Unrealized loss (gain) on foreign exchange	6,723	(10,500)	1,430	343
Unrealized loss (gain) on cross-currency swap	(6,633)	9,884	(1,410)	(292)
Accretion of decommissioning obligations (note 8)	1,865	2,061	6,104	5,085
<b>Total finance expense</b>	<b>\$28,951</b>	<b>\$10,419</b>	<b>\$84,814</b>	<b>\$30,559</b>

### 14. Shareholders' equity:

#### (a) Share capital:

(\$ thousands except number of shares)	September 30, 2023		December 31, 2022	
	Number	Amount	Number	Amount
Balance, opening	556,440,901	\$1,879,250	406,938,099	\$1,242,392
Issue of common shares - cash	–	–	38,334,100	143,753
Issue of common shares - acquisitions	–	–	115,575,033	515,402
Issue of common shares - Option, RSU and PSU exercise	1,502,143	–	3,485,469	–
Purchase of common shares - cancellation	–	–	(4,362,700)	(14,375)
Return of common shares to treasury	–	–	–	(2,646)
Purchase of common shares - treasury	(1,235,050)	–	(3,529,100)	–
Share issue costs, net of tax (2023 - \$nil; 2022 - \$1,576)	–	–	–	(5,276)
<b>Balance, ending</b>	<b>556,707,994</b>	<b>\$1,879,250</b>	<b>556,440,901</b>	<b>\$1,879,250</b>

At September 30, 2023 and at December 31, 2022 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

#### (b) Normal course issuer bid:

Pursuant to the Company's approved NCIB, the Company is permitted to purchase up to 27.8 million Common Shares over a period of twelve months commencing on January 19, 2023. During the nine months ended September 30, 2023, the Company did not purchase and cancel any Common Shares. For the year ended December 31, 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.

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### (c) Treasury shares:

During the nine months ended September 30, 2023, the Company spent \$4.6 million to purchase 1.2 million Common Shares to be used to settle stock options (“Stock Options”), RSUs and PSUs on the date of exercise (December 31, 2022 - \$17.3 million to purchase 3.5 million Common Shares). As at September 30, 2023, 232,670 Common Shares remain classified as treasury shares to be used for future settlements of Stock Options, RSUs and PSUs (December 31, 2022 – 499,763 Common Shares).

### (d) Dividends:

During the nine months ended September 30, 2023, the Company declared \$62.6 million (September 30, 2022 - \$35.8 million) related to its monthly cash dividends on its common shares of \$0.0125 per share (September 30, 2022 - \$0.0083 per share for the first five months of 2022 and \$0.01 per share for the dividend declared on and after June 15, 2022). Included within Accounts payable and accrued liabilities is the dividend payable of \$7.0 million on its common shares of \$0.0125 per share for the dividend declared on September 15, 2023.

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

## 15. Net income per share:

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

(\$ thousands, except per share amounts)	Three months ended September 30,		Nine months ended September 30,	
	2023	2022	2023	2022
Net income	<b>\$8,634</b>	\$124,793	<b>\$36,874</b>	\$294,757
Weighted average shares - basic	<b>556,708</b>	440,388	<b>556,399</b>	431,672
Weighted average shares - diluted	<b>558,569</b>	443,351	<b>559,958</b>	435,053
Net income per share-basic	<b>\$ 0.02</b>	\$ 0.28	<b>\$ 0.07</b>	\$ 0.68
Net income per share-diluted	<b>\$ 0.02</b>	\$ 0.28	<b>\$ 0.07</b>	\$ 0.68

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the three and nine months ended September 30, 2023, 4.6 million and 7.1 million, respectively, 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. For the three and nine months ended September 30, 2022, 5.6 million and 5.8 million, respectively, 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.

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### 16. Share-based payments:

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

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2023	2022	2023	2022
Stock Options	\$25	\$40	\$112	\$135
RSUs	1,949	1,219	5,683	3,114
PSUs	649	335	1,843	1,272
Equity settled stock-based compensation	\$2,623	\$1,594	\$7,638	\$4,521
RSUs	\$(17)	\$(360)	\$376	\$151
PSUs	564	(839)	4,385	–
RIAs	430	356	1,487	675
PIAs	792	189	2,144	594
Cash settled stock-based compensation	\$1,769	\$(654)	\$8,392	\$1,420
Total capitalized costs	\$(1,442)	\$(531)	\$(3,497)	\$(2,196)
Total expensed stock-based compensation	\$2,950	\$409	\$12,533	\$3,745

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 39.0 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:

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, 2022	2,142	\$2.22
Exercised – settled with Treasury shares (note 14)	(646)	2.73
Forfeited/expired	(118)	2.29
Outstanding, December 31, 2022	1,378	\$1.98
Exercised – settled with Treasury shares (note 14)	(160)	2.61
<b>Outstanding, September 30, 2023</b>	<b>1,218</b>	<b>\$1.90</b>

As at September 30, 2023, there were 1.2 million Stock Options issued and outstanding. There were no Stock Options granted during the nine months ended September 30, 2023 (December 31, 2022 – nil).

The range of exercise prices of the Stock Options outstanding and exercisable at September 30, 2023 is as follows:

Range of exercise price	Stock Options outstanding			Stock Options exercisable	
	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	2.0	816	\$1.63
\$ 2.51 – 2.66	222	\$2.60	0.8	185	\$2.57
<b>\$ 0.64 – 2.66</b>	<b>1,218</b>	<b>\$1.90</b>	<b>1.8</b>	<b>1,001</b>	<b>\$1.80</b>

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### (b) PRSU Plan:

The following table summarizes information about the RSUs and PSUs:

	Number of RSUs (thousands)	Number of PSUs (thousands)
Outstanding, January 1, 2022	4,704	4,874
Granted	2,224	1,573
Reinvestment of dividends	59	37
Exercised - settled with shares from Treasury (note 14)	(2,007)	(833)
Exercised - cash payment	(680)	(570)
Forfeited	(328)	(670)
Outstanding, December 31, 2022	3,972	4,411
Granted	2,160	1,408
Reinvestment of dividends	128	70
Exercised - settled with shares from Treasury (note 14)	(901)	(441)
Exercised - cash payment	(334)	(1,140)
Forfeited	(466)	(245)
<b>Outstanding, September 30, 2023<sup>(1)</sup></b>	<b>4,559</b>	<b>4,063</b>
<b>Exercisable, September 30, 2023<sup>(2)</sup></b>	<b>490</b>	<b>192</b>

<sup>(1)</sup> As at September 30, 2023, there are 207 outstanding cash settled RSUs and 1,633 outstanding cash settled PSUs remaining.

<sup>(2)</sup> As at September 30, 2023, there were no exercisable cash settled RSUs and no exercisable cash settled PSUs remaining.

There were 2.2 million RSUs and 1.4 million PSUs granted during the nine months ended September 30, 2023 (December 31, 2022 – 2.2 million RSUs and 1.6 million PSUs).

### (c) Cash Award Incentive Plan:

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, December 31, 2022	434	1,012
Granted	314	1,205
Exercised - cash payment	(145)	–
<b>Outstanding, September 30, 2023</b>	<b>603</b>	<b>2,217</b>
<b>Exercisable, September 30, 2023</b>	<b>–</b>	<b>–</b>

There were 0.3 million RIAs and 1.2 million PIAs granted during the nine months ended September 30, 2023 (December 31, 2022 – 0.5 million RIAs and 1.2 million PIAs).

## 17. Government assistance:

### (a) Decommissioning obligations:

The Company has recorded \$nil and \$0.2 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, 2023, respectively (September 30, 2022 - \$1.5 million and \$2.2 million, respectively).

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(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### (b) Emissions reductions:

On January 16, 2023 the Company entered into an agreement to receive an estimated \$7.8 million of additional funding through its methane conservation program. As at September 30, 2023 the Company has recorded \$34.9 million of combined ERF and Province of Alberta Methane Technology Implementation Program (“MTIP”) funding, which includes \$7.2 million recognized in the nine months ended September 30, 2023. The portion of the funding that is repayable is recognized as a discounted government loan while the remainder is recognized as a government grant under the terms of the ERF and MTIP agreements. The ERF agreements include scheduled repayments for the repayable funding on March 31, 2025, March 31, 2026, March 31, 2027 and March 31, 2028 (see note 12(a)).

## 18. Commitments:

The following table summarizes the Company’s commitments as at September 30, 2023:

(\$ thousands)	2023	2024	2025	2026	2027+
Credit facilities <sup>(1)</sup>	–	200,000	–	655,827	–
SL Notes <sup>(2)</sup>	–	–	–	–	300,000
Interest on SL Notes <sup>(2)</sup>	10,875	21,750	21,750	21,750	10,875
DAP Notes <sup>(3)</sup>	50,000	56,667	–	–	–
Interest on DAP Notes <sup>(3)</sup>	1,546	826	–	–	–
Lease obligations	2,577	3,332	2,610	410	187
Government loan <sup>(4)</sup>	–	–	1,939	6,966	15,573
Take or pay commitments <sup>(5)</sup>	6,638	17,863	18,296	16,266	50,349
Processing commitments <sup>(6)</sup>	2,786	4,692	7,473	7,473	52,884
Gas transportation <sup>(7)</sup>	806	2,680	1,292	172	32
<b>Total</b>	<b>75,228</b>	<b>307,810</b>	<b>53,360</b>	<b>708,864</b>	<b>429,900</b>

<sup>(1)</sup> Term facility matures on October 13, 2024 with annual amortization payments. SLL Facility matures on May 10, 2026 with no mandatory principal repayments prior to maturity. Excludes interest on bank debt as interest payments fluctuate based on floating rates of interest and changes in the outstanding balance.

<sup>(2)</sup> Principal amount of the SL Notes. SL Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

<sup>(3)</sup> Principal amount of the DAP Notes. DAP Notes bear a coupon rate of 5.75%, payable quarterly.

<sup>(4)</sup> Relates to the scheduled payments on the repayable government loan funding receivable from the Government of Canada under the terms of the ERF agreements.

<sup>(5)</sup> Pipeline commitments to deliver crude oil and/or crude oil and condensate for various volumes ranging from minimums of 129 m3/d to 1,589 m3/d at various tariffs ranging from \$9.00/m3 to \$25.22/m3 which expire between December 31, 2023 and December 31, 2030. Certain of these pipeline commitments escalate at 2% per annum.

<sup>(6)</sup> Processing commitments to guarantee firm capacity in various facilities.

<sup>(7)</sup> Gas transportation costs on long term firm contracts which are in various locations at variable rates.

## TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three and nine months ended September 30, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

### 19. 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.

### 20. Assets Held for Sale and Subsequent Events:

The following table summarizes assets held for sale and associated liabilities as at September 30, 2023:

<b>Assets held for sale:</b>	
As at January 1, 2023	-
Transferred from property, plant, and equipment - cost	768,178
Transferred from property, plant, and equipment – accumulated depletion and depreciation	(494,934)
Impairment of assets held for sale	(97,726)
<b>Balance at September 30, 2023</b>	<b>\$175,518</b>
<b>Liabilities associated with assets held for sale:</b>	
As at January 1, 2023	-
Transfer from decommissioning obligations	75,310
<b>Balance at September 30, 2023</b>	<b>\$75,310</b>
<b>Net Assets held for sale</b>	<b>\$100,208</b>

On October 19, 2023, the Company entered into a purchase and sale agreement for the disposition of non-core Cardium oil assets for \$123.0 million in cash. As at September 30, 2023, the Company determined the closing was highly probable of occurring and the assets were available for sale in their present condition. Accordingly, the Company determined that these assets should be reclassified to assets held for sale at September 30, 2023. Immediately after classifying the assets as held for sale, the Company conducted a review of the assets fair value less costs of disposal based on expected consideration to be received and recorded an impairment of assets held for sale of \$97.7 million.

Closing of the transaction is expected to occur on or about November 3, 2023, subject to customary closing considerations. The net asset value of \$100.2 million reflects estimated closing adjustments including transaction costs, net operating income from the effective date and the payout of a facility rental agreement.

Subsequent to September 30, 2023, the Company's Board of Directors declared the monthly cash dividend of \$0.0125 per share on October 17, 2023.

# CORPORATE INFORMATION

## Directors

John Rooney - Chairman <sup>(1)(3)(4)</sup>

Jeff Boyce <sup>(1)(4)</sup>

John Leach <sup>(1)(2)</sup>

Kathleen Hogenson <sup>(2)(4)</sup>

Rob Spitzer <sup>(2)(3)</sup>

Marnie Smith <sup>(1)(3)</sup>

Caralyn Bennett <sup>(2)(4)</sup>

Brian Schmidt

<sup>(1)</sup> Member of the Audit Committee of the Board of Directors

<sup>(2)</sup> Member of the Reserves Committee of the Board of Directors

<sup>(3)</sup> Member of the Compensation & Governance Committee of the Board of Directors

<sup>(4)</sup> Member of the Environmental, Safety and Sustainability Committee of the Board of Directors

## Management Team

Brian Schmidt  
*President & Chief Executive Officer*

Steve Buytels  
*Chief Financial Officer*

Kevin Screen  
*Chief Operating Officer*

Kevin Johnston  
*VP Finance*

Ben Stoodley  
*VP Engineering*

Christine Ezinga  
*VP Corporate Planning & Business Development*

Scott Shimek  
*VP Production & Operations*

Lynne Chrumka  
*VP Exploration*

Sony Gill  
*Corporate Secretary*

## Co-lead Bank Syndicate

National Bank of Canada

Royal Bank of Canada

## Legal Counsel

Stikeman Elliott LLP

## Auditor

KPMG LLP

## Stock Exchange

Toronto Stock Exchange

Stock symbol: TVE

## Contact Information

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