Tamarack Valley Energy Announces Strong Q4 2025 Results, Significant Growth in Clearwater Reserves and Operational Update

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TSX: TVE

Tamarack Valley Energy Ltd. is pleased to announce its financial and operating results for the three months and year e
2025, together with the results of the Company's independent oil and gas reserves evaluation as of December 31, 2025
Tamarack's independent qualified reserves evaluator, McDaniel & Associates Consultants Ltd. Selected financial and o
should be read with Tamarack's audited consolidated financial statements, management's discussion and analysis and
for the year ended December 31, 2025, which are available at www.sedarplus.ca and www.tamarackvalley.ca.

Tamarack has successfully completed its strategic multi-year transformation into a core Clearwater and Charlie Lake pr
tremendous year for the Company, reflecting substantial growth in the profitability of the business from production outp
expansion, improved capital efficiencies, growth in reserves, lower costs and portfolio optimization. For the full year, Ta
return to shareholders of 19%(1), reflecting a combination of production growth, dividends, share buybacks and net deb

For 2026, Tamarack's sustaining free funds flow breakeven cost(1) has declined to ~US$35 per barrel WTI (<US$40 pe
with a corporate production decline rate(2) that is expected to be 22%. With a low-cost structure, low corporate decline r
requirement and low corporate breakeven oil price, Tamarack is well positioned to continue generating sustainable tota
in lower price environments.

2025 Operational and Financial Highlights

- Production - Fourth quarter 2025 production averaged 68,635 boe per day, reflecting a 4% increase over Q4 202
impact of ~4,000 boe per day of non-core production divested in mid October. Tamarack's Clearwater assets deli
in Q4 2025, a 16% increase compared to 43,288 boe per day during same period in the prior year.
- Operating expenses - Net operating expenses per boe(1) declined by 17% year-over-year reflecting the ongoing i
infrastructure, lower costs from waterflood reinjection, higher production, reduced workovers and portfolio optimiz
- Cash flows - In the fourth quarter of 2025, Tamarack delivered cash provided by operating activities of $175.6 mil
of $171.8 million and free funds flow(1) of $70.6 million, or $0.14 per share. For the full year, Tamarack generated
$390.1 million or $0.78 per share, a 10% increase from 2024 despite a 14% decline in WTI prices.
- Shareholder returns - In Q4, Tamarack repurchased 6.8 million common shares for a total cost of $49.4 million ur
program. For the full year, the Company acquired 36.2 million common shares, or 6.9% of the common share floa
$185.3 million (averaging $5.00 per share). Together with base dividends, Tamarack returned $262.3 million to sh
(~$0.52 per share). On February 24, 2026, Tamarack declared a quarterly cash dividend of C$0.04 per share, pa
to shareholders of record at the close of business on March 13, 2026.
- Reserves & resources growth(2) - In 2025, Tamarack increased proved developed producing reserves by 31% to
185% of production year-over-year, with a recycle ratio of 5.2x and finding and development costs of $8.09 per bo
increased by 18% to 282 MMboe, replacing 274% of production. Excluding the impact of acquisitions and non-co
Tamarack's TPP reserves increased by 30% (replacing 413% of production). For the year, Tamarack's contingen
resources (unrisked) also increased by 8% and 6%, respectively.
- Capital investments - Tamarack invested $99.3 million in the fourth quarter of 2025, drilling 24.0 net Clearwater h
and 6.0 injection wells to support ongoing expansion of the waterflood. For the full year, Tamarack invested $400
reduction from 2024, primarily reflecting the impact of declining sustaining capital requirements from strong water
efficiencies from multi-well pad developments and improved run times.
- Waterflood expansion - Tamarack continues to prioritize low-cost, high-margin waterflood investment opportunitie
development areas in tandem with primary drilling activities. The Company exited 2025 with greater than 40,000 b
injection and intends to grow injection rates to 60,000 bbl per day (exit to exit) with more than 35% of Clearwater
waterflood expansion by the end of 2026.

- Coring up the Clearwater - In 2025, Tamarack continued to expand its footprint in the core Clearwater fairway wit acquisitions that included over 145 net sections of stacked Clearwater, Wabiskaw and other potential multi-zone r Marten Hills, Figure Lake, Seal and Pelican asset areas near the Company's core holdings. Tamarack plans to dr Clearwater oil zones at Pelican in 2026. Tamarack now holds over 850 net sections of mineral rights in the Clearw 25% year-over-year growth in the Company's Clearwater land holdings.
- Portfolio optimization - In 2025, Tamarack sold substantially all of its remaining non-core assets in the Southern P areas for gross cash proceeds of $140.0 million before closing adjustments and derecognized $55.3 million of ass (discounted). Since the beginning of 2023, Tamarack has reduced its asset retirement obligations by $155.5 millio 55%, from non-core asset dispositions.

Summary of Tamarack's reserves by year(2)	Clearwater			Corporate Total		
Reserves (MMboe)	2025	2024	2023	2025	2024	2023
Proved developed producing (PDP)	70	43	35	90	69	64
Total Proved (TP)	133	81	67	174	138	128
Total Proved and Probable (TPP)	208	133	113	282	238	224
PDP Reserve Life Index (years)	3.82	2.79	2.42	3.61	2.95	2.61
TPP Reserve Life Index (years)	11.38	8.65	7.83	11.24	10.15	9.17
Finding and Development (F&D $/boe)						
Proved developed producing	$ 6.93	$ 13.84	$ 14.71	$ 8.09	$ 15.20	$ 16.49
Total Proved	7.72	12.24	19.46	8.01	14.16	20.90
Total Proved and Probable	$ 7.33	$ 8.93	$ 19.12	$ 7.93	$ 10.94	$ 20.86
Recycle Ratio						
Operating field netback ($/boe)	$ 45.86	$ 52.56	$ 49.34	$ 41.71	$ 46.41	$ 42.47
Proved developed producing	6.61	3.80	3.35	5.15	3.05	2.58
Total Proved	5.94	4.29	2.54	5.21	3.27	2.03
Total Proved and Probable	6.26	5.89	2.58	5.26	4.24	2.04

2025 Corporate Reserves Highlights(2)

- Growth in reserves - Tamarack delivered significant reserves growth and capital-efficient replacement through the and development programs:
  - PDP reserves increased by 31% to 90 MMboe, replacing 185% of production
  - TP reserves increased by 26% to 174 MMboe, replacing 245% of production
  - TPP reserves increased by 18% to 282 MMboe, replacing 274% of production
  - Excluding reserves and production associated with acquisitions and divestitures in 2025 (~29 MMboe of TP TPP reserves increased by 30%, replacing 413% of production year-over-year.
- Finding and development costs - Tamarack continued to advance its capital efficiency in 2025, supported by high waterflood additions and strong, repeatable performance in the Charlie Lake. Including changes to future develop realized 2025 F&D costs of $8.09/boe (PDP), $8.01/boe (TP) and $7.93/boe (TPP).
- Recycle ratios - Tamarack generated an operating field netback of $41.71 per boe in 2025. Combined with the Co growth in the year, Tamarack delivered higher recycle ratios of 5.15 (PDP), 5.21 (TP) and 5.26 (TPP). The stando the year-over-year PDP recycle ratio was achieved in a pricing environment where near-term WTI benchmark pric results have reinforced the margin durability in a lower price environment and contributed to higher before-tax net discount rate) of $2.2 billion (PDP), $3.4 billion (TP) and $5.4 billion (TPP).
- Per Share Value Growth - Tamarack achieved significant per-share value expansion, increasing debt-adjusted re (PDP) and 28% (TPP) from 2024. This performance was supported by disciplined debt reduction, consistent retur dividends and share buybacks and the addition of low-cost, high-quality reserve volumes.

2025 Clearwater Reserves Highlights(2)

- Growth in reserves - In 2025, Tamarack demonstrated substantial Clearwater reserve growth across all categorie transformative nature of the play through both primary development and secondary recovery:
  - PDP reserves increased by 63% to 70 MMboe, replacing 256% of production
  - TP reserves increased by 64% to 133 MMboe, replacing 401% of production
  - TPP reserves increased by 56% to 208 MMboe, replacing 534% of production
- Finding and development costs - Tamarack's Clearwater assets continued to demonstrate strong capital efficienc of $6.93 per boe (PDP), $7.72 per boe (TP) and $7.33 per boe (TPP).
- Recycle ratios - Together with an operating field netback of $45.86 per boe, the asset delivered recycle ratios of 6 and 6.26x (TPP), reinforcing the Clearwater's high-margin quality that can deliver strong returns even in a lower c environment.
- Waterflood Economics - In 2025, Tamarack's PDP reserves under waterflood expanded by 300%, contributing to reserve life index. This performance reflects waterflood F&D on PDP reserves of less than $3.00 per boe, which t of greater than 18x. At this early stage of development and with only ~37% of Clearwater PDP reserves currently Tamarack's development program is building momentum towards a broader expansion of secondary recovery in t substantial running room.

2025 Corporate Resources Highlights[(2)]

- As at December 31, 2025, Tamarack had "best estimate" gross contingent resources (unrisked) of 115 MMbbl of Clearwater, reflecting an 8% increase over 2024. The Company also held gross prospective resources (unrisked) increase from the prior year. There are 605 net Contingent and 1,008 net Prospective drilling locations identified i Together with reserves, the Resource Report implies that Tamarack has over 2,100 drilling locations. At the Com primary development, that would imply 28 years of potential drilling inventory in the Clearwater.

2025 Operational and Financial Highlights

	Three months ended			Year ended		
December 31	2025	2024	% change	2025	2024	% change
($ thousands, except per share amounts)						
Oil and natural gas sales	$ 365,028	$ 426,482	(14)	$ 1,611,671	$ 1,720,732	(6)
Cash provided by operating activities	175,571	201,798	(13)	778,897	833,212	(7)
Per share - basic	0.36	0.38	(5)	1.55	1.54	1
Per share - diluted	0.35	0.38	(8)	1.54	1.52	1
Adjusted funds flow[(1)]	171,806	223,431	(23)	795,575	850,960	(7)
Per share - basic	0.35	0.42	(17)	1.59	1.57	1
Per share - diluted	0.35	0.42	(17)	1.57	1.56	1
Free funds flow[(1)]	70,592	89,208	(21)	390,119	386,901	1
Per share - basic	0.14	0.17	(18)	0.78	0.71	10
Per share - diluted	0.14	0.17	(18)	0.77	0.71	8
Net income (loss)	61,922	6,382	nm	(36,349)	162,219	nm
Per share - basic	0.13	0.01	nm	(0.07)	0.30	nm
Per share - diluted	0.12	0.01	nm	(0.07)	0.30	nm
Adjusted net income[(1)]	49,633	69,906	(29)	253,342	267,500	(5)
Per share - basic						

0.10

0.13

(23)

0.51

0.49

4

Per share - diluted	0.10	0.13	(23)	0.50	0.49	2
Debt	668,328	738,132	(9)	668,328	738,123	(9)
Net debt(1)	685,716	775,438	(12)	685,716	775,438	(12)
Investments in oil and natural gas assets	99,293	127,311	(22)	400,015	450,905	(11)
Weighted average shares outstanding						
Basic	489,744	529,136	(7)	501,160	542,530	(8)
Diluted	495,712	533,845	(7)	506,619	546,940	(7)
Average daily production						
Heavy oil (bbls/d)	45,451	39,341	16	42,814	38,082	12
Light oil (bbls/d)	10,220	13,822	(26)	12,450	14,271	(13)
NGL (bbls/d)	2,823	2,841	(1)	2,742	2,556	7
Natural gas (mcf/d)	60,846	60,602	-	61,020	56,529	8
Total (boe/d)	68,635	66,104	4	68,176	64,331	6
Average sale prices						
Heavy oil ($/bbl)	$ 65.53	$ 79.69	(18)	$ 73.57	$ 82.37	(11)
Light oil ($/bbl)	75.85	94.30	(20)	85.04	96.12	(12)
NGL ($/bbl)	27.66	32.84	(16)	31.99	37.51	(15)
Natural gas ($/mcf)	2.24	1.71	31	1.96	1.72	14
Total ($/boe)	57.81	70.12	(18)	64.77	73.08	(11)
Benchmark pricing	59.14			64.81		
West Texas Intermediate (US$/bbl)		70.27	(16)		75.72	(14)
Western Canadian Select (WCS) (C$/bbl)	66.88	80.74	(17)	75.06	83.52	(10)
WCS differential (US$/bbl)	11.20	12.56	(11)	11.13	14.76	(25)
Edmonton Par (Cdn$/bbl)	76.58	94.90	(19)	85.63	97.54	(12)
Edmonton Par differential (US$/bbl)	4.25	2.42	76	3.57	4.51	(21)
Foreign Exchange (USD to CAD)	1.39	1.40	(1)	1.40	1.37	2
Operating netback ($/boe)						
Oil and natural gas sales	57.81	70.12	(18)	64.77	73.08	(11)
Royalty expenses	(10.88)	(13.42)	(19)	(12.17)	(14.33)	(15)
Net operating expenses(1)	(6.74)	(7.16)	(6)	(7.43)	(8.91)	(17)
Transportation expenses	(3.39)	(3.30)	3	(3.46)	(3.43)	1
Operating field netback ($/boe)(1)						

36.80

46.24

(20)

41.71

46.41

(10)

Realized commodity hedging loss	(1.46)	(1.59)	(8)	(0.77)	(0.48)	60
Operating netback ($/boe)[1]	$ 35.34	$ 44.65	(21)	$ 40.94	$ 46.93	(11)
Adjusted funds flow ($/boe)[1]	$ 27.21	$ 36.74	(26)	$ 31.97	$ 36.14	(12)

Clearwater Update

Tamarack's Clearwater assets delivered average production of 50,049 boe per day in Q4 2025, a 16% increase compa
day during the same period in the prior year. The growth in production reﬂects the ongoing success of primary dev
response from waterﬂood expansion, lower base declines and a tuck-in acquisition in Q3 2025.

During the three months and year ended December 31, 2025, Tamarack drilled 24.0 and 94.3 Clearwater horizontal he
respectively, for ongoing primary development activities in the Clearwater fairway. For the full year, the Company drilled
converted 16 producers to injection, more than doubling Tamarack's injection well count from the prior year. The Comp
source water wells to support the waterﬂood expansion.

Response from the waterﬂood continued to grow throughout the year, with total heavy oil uplift now estimated to be
per day, or ~10% of Tamarack's Clearwater production. From an operational perspective, investments in water handling
infrastructure have contributed to lower net operating expenses on a per barrel basis with the produced water reinjectio
trucking and disposal requirements.

Incremental oil response from waterﬂood activities in the Clearwater continues to be highly correlated with injection
Tamarack exited 2025 with Clearwater injection rates of more than 40,000 bbl per day, tripling exit-rate injection volume
now has 24% of its Clearwater production under waterflood. 2026 waterflood investments are forecasted to be $100 mi
double that of 2025 in response to the ongoing success of the program. The Company intends to grow injection rates to
the end of 2026 (exit to exit), with greater than 35% of Clearwater oil production under waterflood. Tamarack expects th
investments will further accelerate decline mitigation and lower future reinvestment ratios longer term, which will enable
more torque to growth at higher commodity price cycles.

Charlie Lake Update

Tamarack's Charlie Lake assets delivered average production of 17,610 boe per day in Q4 2025 (68% oil and liquids),
to production of 16,936 boe per day during the same period in the prior year. For the full year, Charlie Lake production
day (67% oil and liquids), reflecting a sustained annualized production profile year-over-year.

The Charlie Lake assets continued to generate high-margin cash flows for the Company in 2025 with operating netbac
$190 million, and free funds flow(1) of more than $70 million, providing meaningful funding contributions towards the Co
share buyback and net debt reduction initiatives during the year.

Tamarack drilled four (4.0 net) horizontal wells in the fourth quarter of 2025 and completed and brought on stream thre
wells. Activities were largely focused in the Pipestone area, where Tamarack was able to direct production to both the n
Albright gas plant and the AltaGas Pipestone II gas plant expansion during the quarter, reflecting a major advancement
egress capacity. For the full year, Tamarack drilled 15 (13.8 net) wells in the Charlie Lake and brought 18 (16.8 net) we
Company continues to drill industry leading wells with initial rates that are meeting or exceeding type curve expectation
Company's recent 100/14-09-073-09W6 well (on stream in November) that has achieved an initial 90-day production ra
barrels per day of oil (2,000 boe per day).

Tamarack plans to maintain a flat exit rate production profile in 2026, utilizing a one-rig program to drill 10 wells at Pipe
Tamarack retains signiﬁcant capital allocation optionality with respect to the Charlie Lake, with suﬃcient owned
processing and egress capacity to support ongoing operations, maintain production and facilitate potential growth acros

2026 Outlook(3)

For the year ended December 31,	2026 (full year)
Capital investments ($ millions)	390 - 410
Annual average production[2] (boe/d)	69,000 - 71,000
Average oil & NGL weighting (%)	84 - 86
Royalty rate (%)	19 - 21
Corporate wellhead price differential - Oil[4] ($/bbl)	1.00 - 1.50
Net operating expense[1] ($/boe)	6.85 - 7.15
Transportation ($/boe)	4.00 - 4.50
Interest ($/boe)	2.70 - 3.10
General and administrative ($/boe)	1.30 - 1.45
Income taxes (% of adjusted funds flow[1] before tax)	10 - 12
2026 Capital Investment Allocation (Approximate %)	
Clearwater (primary)	45
Clearwater (waterflood)	25
Charlie Lake	20
De-risk, exploration and other	10

Tamarack's 2026 outlook is unchanged from the budget announcement in December 2025. Approximately 70% of the Company's 2026 capital investment program is dedicated to the Clearwater for ongoing primary development and waterflood expansion across the Nipisi, West Marten, Marten Hills and South Clearwater areas. Tamarack is allocating 20% of the capital investment budget for ongoing development of the Charlie Lake at Pipestone and Wembley with plans to maintain a flat exit rate production profile. Tamarack's exploration budget includes opportunities in the greater Clearwater fairway. Tamarack plans to drill both the Wabiskaw and Clearwater oil zones at Pelican in 2026.

The Company's capital investment program is expected to deliver year-over-year production growth of ~3%. This measured growth primarily reflects the impact of development activities in 2026 and ongoing waterflood investments in 2024 and 2025. Net production expenses[1] in 2026 are anticipated to decline to ~$7.00 per boe, or 6% compared to the prior year, primarily due to non-core property dispositions in 2025, which carried higher per barrel costs relative to Tamarack's corporate averages on retained assets. The Company also continues to realize lower per barrel costs through field infrastructure investments, lower water handling and trucking costs from waterflood reinjection and reduced workover costs.

Shareholder Returns & Dividend Declaration

In 2025, the Company repurchased 36.2 million common shares at an average price of $5.00 per share and has now reduced the common share count by 12.6% since the commencement of the share buyback program in January 2024. Together with base dividends, Tamarack returned $262.3 million to shareholders in 2025. Tamarack has renewed its normal course issuer bid with the Toronto Stock Exchange, commencing on January 19, 2026. The NCIB allows the Company to purchase up to 47,744,705 Common Shares of the Company over a period of 12 months expiring no later than January 18, 2027.

Tamarack's share buybacks allow the Company to continue generating compounding per share growth over time. Having recently achieved a net debt target of 1x Net Debt to Adjusted EBITDA[1] at US$50 per bbl WTI, the Company will continue to focus on allocating additional free funds flow to share buybacks in 2026.

Tamarack's Board of Directors has declared a quarterly cash dividend on its common shares of C$0.04 per share in accordance with the Company's dividend policy. The dividend will be payable on March 31, 2026, to shareholders of record at the close of business on March 13, 2026. This quarterly cash dividend is designated as an eligible dividend for Canadian income tax purposes. Starting in 2026, Tamarack transitioned to a quarterly dividend schedule targeting the last day of each calendar quarter end.

2025 Reserves Information(2)

The following tables highlight selected information from the Company's reserve report, which have been prepared by McDaniel, a qualified independent reserves evaluator, in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and the most recent publication of the Canadian Oil and Gas Evaluation Handbook ("COGEH"). McDaniel's report has an effective date of December 31, 2025 and a preparation date of January 21, 2026.

All evaluations and summaries of future net revenue are stated prior to the provision for interest, debt service charges or general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. The information included in the "Net Present Values of Future Net Revenue Before Income Taxes Discounted" table below is based on an average of pricing assumptions prepared by the following three independent external reserves evaluators: GLJ, Sproule Associates Limited and McDaniel (the "3-Consultant Average Forecast Pricing"). It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. Columns may not add due to rounding.

Company Reserves Category	Light & Medium Crude Oil Gross (MBbl)	Light & Medium Crude Oil Net (MBbl)	Heavy Crude Oil Gross (MBbl)	Heavy Crude Oil Net (MBbl)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gros (Mboe)
Proved:									
Developed Producing	10,523	8,252	63,970	51,422	75,993	68,524	3,227	2,643	90,386
Developed Non-Producing	797	642	506	455	2,330	2,145	191	166	1,882
Undeveloped	10,018	8,050	60,524	49,505	48,260	43,542	2,771	2,296	81,357
Total Proved	21,339	16,944	125,000	101,382	126,583	114,211	6,189	5,105	173,624
Total Probable	18,810	14,153	69,428	53,541	90,000	80,331	4,813	3,815	108,051
Total Proved and Probable	40,148	31,097	194,428	154,923	216,583	194,543	11,002	8,920	281,676

Future Net Revenue before tax by Production Type

Reserves Category ($000s)	0 %	5 %	10 %	15 %	20 %	($/Mcfe)	($/boe)
Proved:							
Developed Producing	2,676,885	2,433,847	2,151,254	1,926,843	1,749,830	4.86	29.17
Developed Non-Producing	53,703	47,941	43,157	39,294	36,163	4.44	26.63
Undeveloped	2,190,624	1,629,926	1,228,163	936,092	719,812	3.05	18.30
Total Proved	4,921,211	4,111,713	3,422,574	2,902,229	2,505,806	4.00	24.02
Total Probable	3,749,777	2,672,586	1,999,015	1,551,998	1,241,336	3.92	23.55
Total Proved and Probable	8,670,988	6,784,300	5,421,589	4,454,228	3,747,141	3.97	23.85

Gross Reserves Reconciliation (Mboe)	Total Proved	Total Probable	Total Proved and Probable
December 31, 2024	137,647	100,610	238,256
Extensions & Improved Recovery	39,629	26,394	66,023
Discoveries	-	-	-
Technical Revisions	39,853	(6,516)	33,336
Acquisitions	3,308	2,635	5,944
Dispositions	(20,234)	(14,899)	(35,133)
Economic Factors	(1,693)	(173)	(1,866)
Production	(24,884)	-	(24,884)
December 31, 2025	173,624	108,051	281,676

For the year ended December 31, 2025, Tamarack recognized extensions and improved recovery totaling 39.6 MMboe of proved reserves and 66.0 MMboe of proved plus probable reserves. Extensions and improved recovery additions during the year were primarily attributable to development activity in the Company's Clearwater and Charlie Lake assets. Extensions reflect reserves added through the drilling and development of new locations within these core areas. Improved recovery additions were mainly driven by the expansion of the Company's Clearwater waterflood area, which supported the booking of incremental reserves consistent with observed reservoir response and the current development plan.

The Company also recognized technical revisions totaling 39.9 MMboe of proved reserves and 33.3 MMboe of proved plus probable reserves. Technical revisions during the year were largely the result of production outperformance in the Company's Clearwater assets under both primary and waterflood recovery. Revisions reflect updates to reserves estimates based on stronger-than-forecast production performance and improved understanding of reservoir behaviour, as incorporated by the independent qualified reserves evaluator.

During the year, Tamarack divested 20.2 MMboe of proved reserves and 35.1 MMboe of proved plus probable reserves primarily consisting of non-core Southern Penny and Eastern Alberta assets. Acquired proved plus probable reserves of 5.9 MMboe primarily relates to a strategic tuck-in acquisition consisting of approximately 1,100 boe per day of Clearwater heavy oil and natural gas production and over 114 net sections of stacked Clearwater and other potential multi-zone mineral rights in the Clearwater fairway.

Future Development Costs	Total Proved Reserves	Total Proved and Probable Reserves
($000s)		
2026	323,733	370,543
2027	327,308	405,211
2028	336,152	399,783
2029	206,003	387,522
2030 and subsequent	111,211	375,347
Total	1,304,408	1,938,405
10% discounted	1,084,793	1,552,227

Finding, development and acquisition costs ($/boe)	2025	2024	2023	3-year average
Proved:				
Finding, development and acquisition cost	6.56	14.48	36.99	13.64
Finding and development costs	8.01	14.16	20.90	12.88
Acquisition costs	13.20	8.71	9.55	10.94
Proved and Probable:				
Finding, development and acquisition cost	7.24	10.45	103.55	13.92
Finding and development costs	7.93	10.94	20.86	11.88
Acquisition costs	9.55	15.04	7.55	8.79

Investor Call

Tamarack will host a webcast at 9:30 AM MST (11:30 AM EST) on Wednesday February 25, 2026, to discuss the Q4 2025 ﬁnancial results and reserves evaluations as of December 31, 2025. Participants can access the live webcast through links provided on the Company's website. An archive of the webcast will also be made available on the Company's website.

About Tamarack Valley Energy Ltd.

Tamarack is a corporation engaged in the exploration, development, production and sale of oil and natural gas in the Western Canadian Sedimentary Basin. The Company is currently developing two projects in Northern Alberta - a Clearwater heavy oil position at Nipisi, Marten Hills and South Clearwater and a Charlie Lake light oil position at Valhalla, Wembley and Pipestone. Tamarack holds an extensive inventory of low-risk, oil development drilling locations and is pursuing enhanced oil recovery upside across the Company's core asset areas. Tamarack is committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The Company is publicly traded on the Toronto Stock Exchange under the symbol "TVE". For more information, visit www.tamarackvalley.ca.

Reader Advisories

Selected financial and operating information should be read with Tamarack's audited consolidated financial statements and related management's discussion and analysis for the year ended December 31, 2025, which are available on SEDAR+ at www.sedarplus.ca and on Tamarack's website at www.tamarackvalley.ca

Notes to News Release

1. See "Specified Financial Measures".
2. See "Disclosure of Oil and Gas information".
3. 2026 annual guidance numbers are based on average pricing assumptions of: Crude Oil - WTI US$60.00/bbl, Cru $US(4.00)/bbl, Crude Oil - WCS Differential $US(12.75)/bbl, Natural Gas - AECO C$2.75/GJ, Foreign Exchange
4. Oil wellhead deductions for grade specific trading differential (ex CHV), blending requirements, quality differential Tamarack is not marketing (lease transactions).

Disclosure of Oil and Gas Information

Units of measurement

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 upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with 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.

Corporate decline rate

This news release contains metrics commonly used in the oil and natural gas industry, such as corporate decline rate. "Corporate decline rate" represents the percentage decline of the Company's production base, excluding the production from new wells drilled in the year. Corporate decline rate is not a financial measure and does not have a standardized meaning under NI 51-101. This term has been calculated by management and does not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons. Management uses this oil and gas metric for its own performance measurements and to provide shareholders with a measure to compare Tamarack's operations over time. Readers are cautioned that the information provided by these metrics should not be relied upon for investment or other purposes.

Tamarack's corporate decline rate disclosed in this news release is based on primary and waterflood type curves that are internally estimated by the Company's management and represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management believes an average well will achieve, based on methodology that is analogous to wells with similar geological features. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells. Such type curves are useful in understanding management's assumptions of well performance in making investment decisions in relation to development drilling in such areas and for determining the success of the performance of development wells. However, internally prepared type curves do not reflect the type curves used by our independent qualified reserves evaluator in estimating Tamarack's reserves volumes and such type curves have not been assigned reserves or resources. There is no certainty that Tamarack will ultimately recover the internal type curve volumes from the wells it drills. Actual results may vary materially from both primary and waterflood incremental curve estimates.

Product Types

References in this news release to "crude oil" or "oil" refers to light, medium and heavy crude oil product types as defined by NI 51-101. References to "NGL" throughout this news release comprise pentane, butane, propane, and ethane, being all NGL as defined by NI 51-101. References to "natural gas" throughout this news release refers to conventional natural gas as defined by NI 51-101. Clearwater production volumes presented in this news release on a standalone total boe per day basis are comprised of approximately ~91% heavy oil, ~1% NGLs and ~8% natural gas. Charlie Lake production volumes presented in this news release on a standalone total boe per day basis are comprised of approximately ~54% light oil, ~14% NGLs and ~32% natural gas. Total corporate production guidance of 69,000 - 71,000 boe/d: 47,020 - 48,380 bbl/d heavy oil, 9,070 - 9,330 bbl/d light/med. oil, 2,560 - 2,640 bbl/d NGL and 62,100 - 63,900 mcf/d natural gas.

90-day production rate (IP 90)

With respect to the 90-day production rates reported on Tamarack's 100/14-09-073-09W6 well, the production rate is based on field estimates and excludes seven days during the period where the well was shut-in due for tie-in activities in November. The production breakdown of the 2,000 boe per day is as follows: 1,400 bbl per day light and medium oil, 100 bbl per day NGL and 3,000 mcf per day of natural gas.

Annual Information Form

Tamarack's Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1 dated effective as at December 31, 2025, which includes further disclosure of Tamarack's oil and gas reserves and other oil and gas information in accordance with NI 51-101 and COGEH forming the basis of this news release, is included in the Annual Information Form which is available on SEDAR+ at www.sedarplus.ca or the Company's website at www.tamarackvalley.ca.

Reserves and Future Net Revenue Disclosures

All reserves values, future net revenue and ancillary information contained in this news release are derived from the Reserve Reports unless otherwise noted. All reserve references in this news release are "Company Gross Reserves". Company Gross reserves defined as working interest share of reserves prior to royalty deductions. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to the effect of aggregation. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Tamarack's reserves will be attained and variances could be material. All reserves assigned in the Reserve Reports are located in the Province of Alberta.

All evaluations and summaries of future net revenue are stated prior to the provision for interest, debt service charges or general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. There are numerous uncertainties inherent in estimating quantities of crude oil, reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only.

Proved reserves 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 equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty. Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. Certain terms used in this news release but not defined are defined in NI 51-101, CSA Staff Notice 51-324 - Revised Glossary to NI 51-101 ("CSA Staff Notice 51-324") and/or the COGEH and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGEH, as the case may be.

Resources disclosure

Tamarack's heavy oil Clearwater contingent resource and prospective resource estimates contained herein were derived from the Resource Report prepared by McDaniel, a qualified independent resource evaluator, effective as of December 31, 2025, in accordance with the definitions, standards and procedures contained in NI 51-101 and COGEH. The contingent and prospective resources estimates of Tamarack's Clearwater heavy oil contingent resources provided herein are estimates only and there is no guarantee that the estimated prospective and contingent resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and the differences may be material. Tamarack's Statement of Contingent and Prospective Resources dated February 24, 2026, which has been filed on SEDAR+ at www.sedarplus.ca, includes further disclosure of Tamarack's contingent and prospective resources, including the risks and uncertainties related thereto. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Prospective resources are those quantities of heavy oil estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be subclassified based on project maturity. Estimates of prospective resources have not been adjusted for risk based on the chance of discovery or the chance of development. Resources are classified according to degree of certainty associated with those estimates. In this news release, "best estimate" classification is used which is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources identified as best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

This news release may disclose Clearwater drilling locations two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved and probable locations derived from the McDaniel Reserve Report prepared in accordance with NI 51-101 and the most recent publication of the COGE Handbook. Unbooked locations do not have attributed reserves. However, the unbooked Clearwater locations have attributed contingent or prospective resources, based on the Resource Report. Of the Clearwater inventory of 2,133 (net) drilling locations identified herein, 520 (net) are proved or probable locations, and 1,613 (net) are unbooked locations. Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Reserves definitions

This news release contains metrics commonly used in the oil and natural gas industry, such as development capital, F&D costs, FD&A costs and recycle ratio. "Development capital" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital presented herein excludes land and capitalized administration costs but includes the cost of acquisitions and capital associated with acquisitions where reserve additions are attributed to the acquisitions.

"Finding and development costs" or "F&D costs" are calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period and "finding, development and acquisition costs" are calculated as the sum of field capital plus acquisition capital plus the change in FDC for the period divided by the change in total reserves, other than from production, for the period. Both finding and development costs and finding development and acquisition costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this news release because acquisitions and dispositions can have a significant impact on Tamarack's ongoing reserves replacements costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. "Finding, development and acquisition costs" or "FD&A costs" incorporate the change in FDC required to bring proved undeveloped and developed reserves into production. In all cases, the FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions after changes in FDC costs. The Clearwater F&D metric reported in this news release includes a proportionate share of general and administrative costs based on the TPP reserve volume weighting of 74% (% of total TPP reserves).

"Recycle ratio" is measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves.

These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Tamarack's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this news release, should not be relied upon for investment or other purposes.

Forward Looking Information

This news release contains certain forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian securities laws. Forward-looking statements are often, but not always, identified by the use of words such as "budget", "guidance", "outlook", "anticipate", "target", "plan", "continue", "intend", "consider", "estimate", "expect", "may", "will", "should", "could" or similar words (including negatives or grammatical variations) suggesting future outcomes. More particularly, this news release contains statements concerning: Tamarack's business strategy, objectives, strength and focus; the Company's exploration and development plans and strategies; Tamarack's continued prioritization of low-cost, high-margin waterflood investment opportunities in the core Clearwater development areas in tandem with primary drilling activities; the Company's intent to grow injection rates to 60,000 bbl per day (exit to exit), with greater than 35% of Clearwater oil production under waterflood by the end of 2026; expectations that, with a low-cost structure, low corporate decline rate, low reinvestment requirement and low corporate breakeven oil price, Tamarack is well positioned to continue generating sustainable total returns for shareholders in lower price environments through a combination of measured growth, share buybacks, debt reduction and the base dividend; Tamarack's forecasted ~$7.00 per boe run-rate in 2026; expectations that reinforcing the Clearwater's high-margin quality can deliver strong returns even in a lower commodity price environment; expectations that Tamarack's development program is building momentum towards a broader expansion of secondary recovery in the Clearwater fairway with substantial running room; expectations that, at current rates of primary development, the Resource Report implies that Tamarack has 28 years of potential drilling inventory in the Clearwater; capital investments of $390 - 410 million in 2026 and the allocation thereof, annual average production of 69,000 - 71,000 boe/day, average oil and natural gas weightings of 84 - 86%, royalty rates of 19 - 21%, corporate wellhead price differentials - oil of $1.00 - 1.50 per boe, net operating expenses of $6.85 - 7.15 per boe, transportation expenses of $4.00 - 4.50 per boe, general and administrative expenses of $1.30 - 1.45 per boe, interest expense of $2.70 - 3.10 per boe and income taxes as a % of adjusted funds flow before tax of 10 - 12%; 45% of capital in 2026 being allocated to Clearwater primary, 25% to Clearwater waterflood, 20% to Charlie Lake and 10% to de-risk, exploration and other; approximately 70% of the Company's 2026 capital investment program being dedicated to the Clearwater for ongoing primary development and waterflood expansion across the Nipisi, West Marten, Marten Hills and South Clearwater areas; waterflood investments being forecasted to be $100 million; expectations that expanded waterfloods investments will further accelerate decline mitigation and lower future reinvestment ratios longer term; expectations that the Company's 2026 capital investment program will deliver year-over-year production growth of ~3%; expectations that net operating expenses in 2026 will decline to ~$7.00 per boe; expectations that the Company will continue to drill industry leading wells with initial rates that meet or exceed type curve expectations; In addition, statements related to "reserves", "resources" and "recovery" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates, that the resources can be discovered and profitably produced in the future.

Future dividend payments and share buybacks, if any, and the level thereof, are uncertain, as the Company's return of capital framework and the funds available for such activities from time to time is dependent upon, among other things, free funds flow financial requirements for the Company's operations and the execution of its 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 buyback shares 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.

The forward-looking statements contained in this document are based on certain key expectations and assumptions made by Tamarack, including those relating to: the business plan of Tamarack; execution of the Company's 2026 budget; the timing of and success of future drilling, conversion, development and completion activities; the geological characteristics of Tamarack's properties; prevailing commodity prices, price volatility, price differentials and the actual prices received for the Company's products; the realization of anticipated benefits of the Company's infrastructure, waterflood development program and recent acquisitions and divestitures; the availability and performance of drilling rigs, facilities, pipelines and other oilfield services; the timing of past operations and activities in the planned areas of focus; the performance of new and existing wells; the application of existing drilling and fracturing techniques; the Company's ability to secure sufficient amounts of water; prevailing weather and break-up conditions; royalty regimes and exchange rates; impact of inflation on costs; the application of regulatory and licensing requirements; the continued availability of capital and skilled personnel; the ability to maintain or grow the banking facilities; the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation; and Tamarack's ability to execute its plans and strategies.

Although management considers these assumptions to be reasonable based on information currently available, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurances that they may prove to be correct. By their very nature, forward-looking statements are subject to certain risks and uncertainties (both general and specific) that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking statements. These risks and uncertainties include, but are not limited to: risks with respect to unplanned third party pipeline outages and risks relating to inclement and severe weather events and natural disasters, such as fire, drought and flooding, including in respect of safety, asset integrity and shutting-in production; the risk that future dividend payments thereunder are reduced, suspended or cancelled; incorrect assessments of the value of benefits to be obtained from exploration and development programs; risks associated with the oil and gas industry in general (e.g. operational risks in development, exploration and production; and delays or changes in plans with respect to exploration or development projects or capital expenditures); the risk that (i) the U.S. and Canadian governments maintain tariffs, increase the rate or scope of tariffs, or impose new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company; commodity prices, including the impact of the actions of OPEC and OPEC+ members; risks relating to reliance on third parties, including in respect of the Company's use of third-party infrastructure at Charlie Lake; the uncertainty of estimates and projections relating to production, cash generation, costs and expenses, including increased operating and capital costs due to inflationary pressures; health, safety, litigation and environmental risks; access to capital; and pandemics. In addition, ongoing military actions in Venezuela, the Middle East and between Russia and Ukraine have the potential to threaten the supply of oil and gas from those regions. The long-term impacts of the actions between these nations remains uncertain. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to respond to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Please refer to the most recent annual information form and management's discussion and analysis of the Company, for additional risk factors relating to Tamarack, which can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedarplus.ca. The forward-looking statements contained in this news release are made as of the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included statements, except as required by law. The forward-looking statements contained herein are qualified by this cautionary statement.

This news release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about generating sustainable long-term growth in free funds flow, dividends, share buybacks and debt reduction, the 2026 capital budget of $390 - 410 million, guidance and budget pricing and allocation, including prospective results of operations, production (including annual average production of 69,000 - 71,000 boe/day, average oil and natural gas weightings of 84 - 86%, production growth of 3% and free funds flow, operating costs (including net operating expenses in 2026), balance sheet strength, and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this document was approved by management as of the date of this document and was provided for the purpose of providing further information about Tamarack's future business operations. Tamarack and its management believe that FOFI 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, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. Tamarack disclaims any intention or obligation to update or revise any FOFI contained in this document, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this document should not be used for purposes other than for which it is disclosed herein. Changes in commodity prices, differences in the timing and allocation of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in Tamarack's guidance. Actual results may differ materially from these estimates.

Specified Financial Measures

This news release includes various specified financial measures, including non-IFRS financial measures, non-IFRS financial ratios, capital management measures and supplemental financial measures as further described herein. These measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculation of similar measures by other companies.

Reserves per share is the Company's total crude oil, NGL and natural gas reserves volumes for the applicable period divided by the weighted average number of diluted shares outstanding for the applicable period. Reserves per share growth is determined in comparison to the applicable comparative period. Debt-adjusted reserves per share is calculated as year end reserves divided by year end fully diluted shares plus the annual change in net debt divided by the average annual share price for 2025. Debt-adjusted reserves per share growth is determined in comparison to the year end reserves divided by year end fully diluted shares from the applicable comparative period.

Net Operating Expenses (Non-IFRS Financial Measures, and Non-IFRS Financial Ratio if calculated on a per boe basis) is calculated as operating expenses less processing income. Tamarack generates processing income from third parties that utilize excess capacity at Tamarack's facilities. If Tamarack has excess capacity at one of its facilities, the Company will seek to process third-party volumes as a means of offsetting a portion of the facility costs. Accordingly, net operating expenses allow Tamarack and others to assess the profitability of field operating results by including the associated income generated from plant operations.

Adjusted funds flow (capital management measure) is defined as cash provided by operating activities excluding asset retirement obligation expenditures, transaction costs and changes in non-cash working capital. Asset retirement obligation expenditures and transactions costs from business combinations both result from the Company's capital budgeting and strategic planning processes, which first considers available adjusted funds flow. Asset retirement obligation expenditures vary from period to period depending on capital programs, government regulations and the maturity of the Company's operating areas. By also excluding changes in non-cash working capital from cash provided by operating activities, the adjusted funds flow measure provides a meaningful metric for Tamarack and others by establishing a clear link between the Company's cash flows, income statement and operating netbacks by isolating the impact of changes in the timing between accrual and cash settlement dates, which can often be within management's control. Tamarack uses adjusted funds flow to assess the Company's financial performance and cash generated from operating activities.

Free funds flow (capital management measure) is defined as adjusted funds flow less investments in oil and natural gas assets (excluding acquisitions and dispositions) and the settlement of asset retirement obligations. Management utilizes free funds flow to assess how much cash was generated in excess of the Company's capital investment and asset retirement programs within the same period, which can be utilized to reduce debt, fund acquisitions or return capital.

Net debt (capital management measure) is calculated as the sum of the Company's debt, government loans and other, cash, accounts receivable, prepaid expenses and deposits, cross-currency swap liability (asset), assets held for sale (net), accounts payable and accrued liabilities. Tamarack and others utilize net debt to assess liquidity and balance sheet strength by aggregating the select financial assets and financial liabilities on the Company's balance sheet.

Adjusted EBITDA (capital management measure) is calculated as net income (loss) before interest, income taxes, depletion, depreciation, impairment losses, non-cash expenses, unrealized gains (losses) and other non-recurring items. Tamarack uses adjusted funds flow to assess financial performance. Net debt to adjusted EBITDA (capital management ratio) is calculated as net debt divided by Adjusted EBITDA and provides a measure of earnings relative to debt levels.

Operating Netback equals total oil and natural gas sales, including realized gains and losses on commodity hedges, less royalties, net operating expenses and transportation expenses. Operating Field Netback equals total oil and natural gas sales, less royalties, net operating expenses and transportation expenses. 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 performance by asset area by isolating the impact of corporate and other overhead related expenditures.

Sustaining capital (supplementary financial measure) represents management's estimate of annual capital investments required to maintain corporate production at prior period levels. This measure allows Management and others to assess the approximate composition of Tamarack's annual capital investment programs and its corporate financial sustainability. Sustaining capital is also utilized to calculate the Company's free funds flow breakeven cost.

Free funds flow breakeven cost (capital management measure) reflects the average minimum WTI price (US per bbl) received by Tamarack where adjusted funds flow net of the base dividend and sustaining capital requirements is approximately equivalent to zero, with sustained current hedged production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability.

The calculation of Tamarack's free funds flow breakeven cost of US$35 per bbl was primarily determined by utilizing the ranges within budget assumptions included in the table on page 1 of this news release, other than for capital investments, which utilize the Company's sustaining capital requirements of $265.0 million under an assumed scaled-budget, break-even price scenario, and average royalty rates which would be expected to decline to 14 - 15% at WTI price of $35 per bbl. Other assumptions utilized by the Company to calculate the free funds flow breakeven cost includes annual dividends of $0.16 per share, hedging gains of $4.67 per boe and asset retirement obligation expenditures of $5.0 million.

Total return to shareholders provides an estimate of the total return generated for shareholders on a percentage basis by aggregating certain select metrics consisting of production growth, dividends, share buybacks and net debt reduction (for a total return of 19% in 2025). The return from production growth is calculated as the year-over-year % change in production (6%), dividend growth is based on the yield during year relative to TVE's average market capitalization (3%), share buybacks is calculating as the number of shares purchased in the year divided by TVE's opening common share count (7%) and net debt reduction is based on the year-over-year net debt decline relative to TVE's average market capitalization (3%).

Please refer to the management's discussion and analysis for additional information relating to specified financial measures including non-IFRS financial measures, non-IFRS financial ratios and capital management measures. The management's discussion and analysis can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedarplus.ca.

Abbreviations

bbl(s)	barrel(s)	MMboe	million barrels of oil equivalent
bbls/d	barrels per day	NGL	natural gas liquids
boe	barrels of oil equivalent	PDP	proved developed producing
boe/d	barrels of oil equivalent per day	TP	total proved
F&D	finding and development	TPP	total proved plus probable
Mboe	thousand barrels of oil equivalent	WTI	West Texas Intermediate, the reference pr
Mcfe	1,000 cubic feet equivalent on the basis of 1 bbl of crude oil for six thousand cubic feet of natural gas		at Cushing, Oklahoma for the crude oil sta

SOURCE Tamarack Valley Energy Ltd.

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