TSX: TVE

Tamarack Valley Energy Announces Year-End 2023 Financial & Reserve Results, Clearwater Resource Evaluation and Provides Operational and Guidance Update Including Executive Appointment

Calgary, Alberta – February 28, 2024 – Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") (TSX: TVE) is pleased to announce its audited financial and operating results for the three months and year ended December 31, 2023 and the results of Tamarack's year-end independent oil and gas reserves evaluations as of December 31, 2023 (the "Reserve Reports"), prepared by Tamarack's independent qualified reserves evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel) and GLJ Ltd. ("GLJ"). Selected reserves, financial and operating information is outlined below. Selected financial and operating information should be read with Tamarack's audited annual consolidated financial statements and related management's discussion and analysis ("MD&A") for the three and twelve months ended December 31, 2023, and the Company's Annual Information Form ("AIF") for the year ended December 31, 2023, which are available on SEDAR+ at www.sedarplus.ca and on Tamarack's website at www.tamarackvalley.ca.

2023 Financial and Operational Highlights

- ***Improved Balance Sheet Strength*** – YoY net debt(1) reduction of $373MM (equal to approximately $0.67 per share) to exit the year with net debt of $984MM.
- ***Improved Operating Costs*** – Production expense of $8.89/boe in Q4/23 reflected a 16% QoQ improvement demonstrating the benefits of core area production growth, program efficiencies and disposition of assets with higher costs.
- ***Low-Cost Organic Reserves Growth*** **–** Increased proved developed producing ("PDP") reserves by 15% (representing 137% of production) at a finding and development ("F&D") cost of $16.49/boe and total proved plus probable ("TPP") reserves by 13% (representing 214% of production) at a F&D cost of $20.86/boe, net of dispositions(2).
- ***Achieved Enhanced Return of Capital Threshold*** – Delivered on Tamarack's commitment to achieve the first threshold of our enhanced return of capital framework. As a result, subsequent to year-end, the Company was able to accelerate enhanced returns through the buyback of shares as part of our Normal Course Issuer Bid ("NCIB").
- ***Increased Oil Production Weighting*** – Delivered annual production of 67,034 boe/d(3), inline with guidance. Fourth quarter production of 64,881 boe/d(4), reflected ~4,500 boe/d(5) from non-core asset sales and unplanned third party restrictions in the Charlie Lake. Tamarack's oil and liquids weighting as a percent of total production increased to 85% in Q4 2023 compared to 82% in Q4 2022.
- ***Optimized Capital Spending*** – Total capital expenditures in 2023 of $516MM included: $21MM of gas conservation projects sanctioned with the Clearwater Infrastructure Limited Partnership (the "CIP"), $20MM accelerated from the 2024 capital budget and $475MM allocated to Tamarack's development program. Development spending was inline with the upper end of the $425 - $475MM guidance. Accelerated capital of $20MM into 2023 from 2024 represented an opportunity to take advantage of favorable field conditions and services pricing which will result in an equal reduction to 2024 spending.
- ***Free Funds Flow(1) Generation*** – Delivered $248MM of free funds flow(1) during the year which was directed to dividends and debt repayment.
- ***Strategic Infrastructure Partnership*** – Entered into a series of agreements with 12 First Nation and Metis communities (the "Indigenous Communities") to establish the CIP, enhancing the long-term relationships between Tamarack and the Indigenous Communities. As part of this transaction, Tamarack received gross proceeds of $146MM and a 15% working interest in the CIP while retaining operatorship and full access to 100% of Tamarack's existing mid-stream capacity.

2023 Financial & Operating Results

	Three months ended December 31,			Year ended December 31,		
	2023	2022	% change	**2023**	2022	% change
($ thousands, except per share amounts)						
Oil and natural gas sales	**$ 418,864**	$ 422,313	(1)	**$1,702,930**	$ 1,455,448	17
Cash flow from operating activities	**215,981**	227,889	(5)	**631,626**	805,377	(22)
Per share – basic	**0.39**	0.42	(7)	**1.13**	1.75	(35)
Per share – diluted	**0.39**	0.42	(7)	**1.13**	1.73	(35)
Adjusted funds flow (1)	**194,771**	196,746	(1)	**764,494**	727,061	5
Per share – basic (1)	**0.35**	0.36	(3)	**1.37**	1.58	(13)
Per share – diluted (1)	**0.35**	0.36	(3)	**1.37**	1.57	(13)
Free funds flow (1)	**67,067**	71,470	(6)	**248,038**	268,484	(8)
Per share – basic (1)	**0.12**	0.13	(8)	**0.45**	0.58	(24)
Per share – diluted (1)	**0.12**	0.13	(8)	**0.44**	0.58	(23)
Net income	**57,322**	50,441	14	**94,196**	345,198	(73)
Per share – basic	**0.10**	0.09	11	**0.17**	0.75	(77)
Per share – diluted	**0.10**	0.09	11	**0.17**	0.74	(77)
Net debt (1)	**(983,585)**	(1,356,570)	(27)	**(983,585)**	(1,356,570)	(27)
Investments in oil and natural gas assets	**127,704**	125,276	2	**516,456**	458,577	13
Weighted average shares outstanding						
Basic	**556,699**	545,118	2	**556,527**	460,345	21
Diluted	**560,008**	549,062	2	**560,032**	464,276	21
Average daily production						
Light oil (bbls/d)	**14,928**	17,382	(14)	**16,326**	17,423	(6)
Heavy oil (bbls/d)	**37,447**	31,328	20	**35,788**	15,768	127
NGL (bbls/d)	**2,769**	4,241	(35)	**3,536**	3,888	(9)
Natural gas (mcf/d)	**58,419**	68,355	(15)	**68,302**	67,221	2
Total (boe/d)	**64,881**	64,344	1	**67,034**	48,283	39
Average sale prices						
Light oil ($/bbl)	**$ 99.79**	$ 103.37	(3)	**$ 98.64**	$ 115.47	(15)
Heavy oil, net of blending expense(1) ($/bbl)	**74.09**	71.36	4	**75.61**	85.40	(11)
NGL ($/bbl)	**42.31**	50.53	(16)	**41.67**	54.66	(24)
Natural gas ($/mcf)	**2.82**	4.89	(42)	**2.84**	6.15	(54)
Total ($/boe)	**70.07**	71.19	(2)	**69.48**	82.54	(16)
Benchmark pricing						
West Texas Intermediate (US$/bbl)	**78.32**	82.65	(5)	**77.62**	94.23	(18)
Edm Par differential (US$/bbl)	**5.19**	1.66	213	**3.25**	1.79	82
WCS differential (US$/bbl)	**21.89**	25.89	(15)	**18.70**	18.27	2
Edmonton Par (Cdn$/bbl)	**99.69**	109.97	(9)	**100.39**	120.05	(16)
Hardisty Heavy (Cdn$/bbl)	**76.96**	77.09	–	**79.53**	98.43	(19)
Foreign exchange (USD to CAD)	**1.36**	1.36	–	**1.35**	1.30	4
Operating netback ($/Boe)						
Average realized sales, net of blending expense (1)	**70.07**	71.19	(2)	**69.48**	82.54	(16)
Royalty expenses	**(13.81)**	(15.07)	(8)	**(12.97)**	(16.01)	(19)
Net production expenses (1)	**(8.89)**	(10.54)	(16)	**(9.49)**	(10.38)	(9)
Transportation expenses	**(3.56)**	(3.64)	(2)	**(3.90)**	(2.88)	35
Carbon tax	**(2.53)**	(0.01)	nm	**(0.65)**	0.03	nm
Operating field netback ($/Boe) (1)	**41.28**	41.93	(2)	**42.47**	53.30	(20)
Realized commodity hedging gain (loss)	**0.80**	0.31	158	**(1.23)**	(3.52)	(65)
Operating netback ($/Boe) (1)	**$ 42.08**	$ 42.24	–	**$ 41.24**	$ 49.78	(17)
Adjusted funds flow ($/Boe) (1)	**$ 32.63**	$ 33.24	(2)	**$ 31.25**	$ 41.26	(24)

Brian Schmidt, President and CEO of Tamarack stated

"Tamarack completed its strategic transformation in 2023, integrating the three corporate Clearwater acquisitions that closed in 2022 and divesting our non-core west central Alberta Cardium assets, affording our team the ability to focus on our core Clearwater, Charlie Lake and EOR assets. Most importantly, we delivered on a key commitment to our shareholders to reduce our net debt(1) and achieved the first threshold of our enhanced return of capital framework with share buybacks commencing in January 2024.

In addition, we continued to realize significant value generation from the assets acquired pursuant to the acquisition of Deltastream Energy Corp. Since close of the acquisition in October 2022, Tamarack has grown production on the Deltastream assets by 29%. Reflecting the highly economic nature of the Clearwater, the assets delivered ~230MM of free NOI(6) in 2023. Incremental to that, the 2023 year-end BTAX TPP NPV10(7) of the assets increased to over $1.8 billion. Overall this transaction continues to exceed our expectations while providing long term development visibility."

2023 Reserves Report Highlights

Tamarack's drilling program combined with continued development of Clearwater waterflood contributed significantly to the 2023 reserves, further enhancing the long-term resiliency and sustainability of free funds flow for the Company moving forward. Key highlights of the Company's PDP, total proved ("TP") and TPP reserves from the Reserves Report are highlighted below:

- ***Strong Development Program Results*** – Excluding reserves and production associated with the dispositions(2), Tamarack's capital program delivered strong results in 2023:
    - PDP reserves increased by 15% to 64 MMboe(8) and replaced 137% of production
    - TP reserves increased by 18% to 128 MMboe(9) and replaced 189% of production
    - TPP reserves increased by 13% to 224 MMboe(10) and replaced 214% of production
- ***Attractive Finding and Development ("F&D") Costs*** – Focused execution in the Charlie Lake and Clearwater achieved the following F&D costs, including changes in Future Development Capital ("FDC"):
    - PDP reserves: $16.49/boe
    - TP reserves: $20.90/boe
    - TPP reserves: $20.86/boe
- ***Strong Recycle Ratios*** – Tamarack's highly economic oil plays delivered an annual operating netback(1) of $42.47/boe. Coupled with low-cost reserve additions the Company delivered the following recycle ratios(1):
    - PDP: 2.6x
    - TP: 2.0x
    - TPP: 2.0x
- ***Increased Oil Weighting*** – Overall liquids-weighting increased YoY by 7%, with 2023 TPP reserves comprised of 85% oil and NGLs and 15% natural gas.
- ***Significant Intrinsic Value*** - Realized before-tax net present value of booked reserves(7)
    - ***PDP NPV10***: $1.6 billion
    - ***TP NPV10***: $2.6 billion
    - ***TPP NPV10:*** $4.5 billion
- ***Charlie Lake Pool Extensions*** - The Company's Charlie Lake assets continued to add material pool extensions in 2023, contributing to reserves growth in the play of 4% and 147% production replacement on a TPP basis. Through ongoing optimization and additions to the Company's land position the percentage of booked TPP locations exceeding 2.5 miles of lateral length increased from 35% to 46% YoY.
- ***Clearwater Assets & Waterflood Value Contribution*** - The Company's Clearwater assets realized significant reserves growth in 2023, delivering increased bookings of 43% and 28% for TP and TPP reserves respectively. The TPP increase replaced 279% of 2023 Clearwater production. At year-end 2023, 12% of total Clearwater TPP reserves were associated with waterflood (3% at 2022 year-end), indicating the continued opportunity for reserves growth as waterflood development continues. In support of converting our resource to booked reserves and realized funds flow Tamarack has allocated capital within the 2024 budget to materially increase water injection rates from ~4,000 bbl/d at year-end 2023 to over 15,000 bbl/d by the end of 2024.

- ***Contingent and Prospective Resource Evaluation*** – With the integration of the three Clearwater consolidating transactions complete, Tamarack retained McDaniel to evaluate and prepare a report (the "Resource Report") on the heavy oil contingent and prospective resources of the Company's Clearwater assets as at December 31, 2023.
  - The Resource Report indicates Tamarack's Clearwater heavy oil assets have a "best estimate" of Company gross Contingent Resources (unrisked) of 89.5 MMbbl(12) and Company gross Prospective Resources (unrisked) of 118.4 MMbbl(13).
  - Inventory attributed to the Company's Clearwater assets within the Report totals 592 net Contingent and 1,182 net Prospective drilling locations. When combined with the Company's 381 net TPP locations included in the year-end evaluation, the identified Clearwater inventory exceeds 2,100 locations.
  - With Clearwater assets producing approximately 13 MMbbl of heavy oil in 2023, TPP reserves represent eight years of equivalent production. Unrisked best estimate contingent and prospective resources equate to approximately seven and nine years of equivalent production, respectively.
  - See "*Reader Advisories - Resource Disclosure*" below and our supplementary filing titled "*Statement of Contingent and Prospective Resources*" dated February 28, 2024 which has been filed on SEDAR+ at www.sedarplus.ca for additional details with respect to Tamarack's contingent and prospective resources, including the risks and uncertainties related thereto.

2023 Reserves Snapshot by Category

	PDP	TP	TPP
Company Gross Reserves (mboe)(8)(9)(10)	63,886	127,830	224,277
NPV10 Before Tax ($MM)(7)	1,612	2,562	4,475

During 2023 Tamarack was successful in divesting certain of its non-core assets, including the west central Cardium assets, which were weighted ~60% to natural gas. This change is reflected in the YoY table below.

Year-Over-Year Reserves Data (Forecast Prices and Costs)

(mboe)	December 31, 2023(14)	December 31, 2022(15)	% Change
PDP	63,866	75,744	(18.6%)
TP	127,830	135,066	(5.6%)
TPP	224,277	242,192	(8.0%)

2024 Capital Guidance Update

Exiting 2023, Alberta saw favorable weather for ongoing field activity through to the end of December. As a result, Tamarack was able to leverage the availability of service providers to accelerate $20MM of the dedicated H1 2024 budget into 2023. Owing to this acceleration the Company has updated its 2024 capital spending guidance associated with the previously disclosed Base Budget to a range of $390 - $440MM. In addition, 2024 carbon tax expense guidance has been reduced. In total, the acceleration of capital and adjustment to the carbon tax treatment serve to increase free funds flow(1) by approximately $35MM in 2024.

Within Tamarack's 2024 program the Company continues to retain significant capital flexibility enabling the adjustment to plans should it see further downside oil price volatility while not expecting to impact 2024 production guidance which is maintained at the 61,000 to 63,000 boe/d(16) range. Tamarack will continue to monitor timing of the CSV Albright sour gas plant where the Company proactively secured firm processing capacity in support of its ongoing Charlie Lake development program. Any decision to commence drilling associated with project will be subject to prevailing commodity prices and expected CSV on-stream timing. The Company does have the ability to swing production from existing wells to this facility to utilize its capacity ahead of implementing any additional drilling.

Updated 2024 Annual Base Budget Guidance Summary at 2024 Budget Pricing(17)

	Units	Prior Base Budget Guidance	**Updated Base Budget Guidance**
Capital Budget(18)	$MM	$410 – $460	$390 - $440
Annual Average Production(16)	boe/d	61,000 – 63,000	61,000 – 63,000
Average Oil & NGL Weighting	%	84% – 86%	84% – 86%
Expenses:			
Royalty Rate (%)	%	20% – 22%	20% – 22%
Net Production	$/boe	$8.75 – $9.25	$8.75 – $9.25
Transportation	$/boe	$3.25 – $3.60	$3.25 – $3.60
Carbon Tax(19)	$/boe	$1.00 – $1.50	$0.50 – $1.00
General and Administrative (20)	$/boe	$1.35 – $1.50	$1.35 – $1.50
Interest	$/boe	$3.80 – $4.20	$3.80 – $4.20
Income Taxes(21)	%	9% - 11%	9% - 11%

2024 Operations Update

Charlie Lake

Tamarack continues to see strong results from its drilling and development program in the Charlie Lake. In Q1/24 the Company commenced flowback operations on the 11-11-074-08W6 pad with initial 30-day production rates per well exceeding 1,000 bbl/d oil and 1,400 boe/d(22). Initial oil production rates from the 11-11-074-08W6 pad are 60% higher than 2023 wells drilled at Wembley reflecting strong reservoir quality, benefits of extended lateral length and reduced facility constraints. Expansion of Tamarack's 16-35-073-08W6 battery at Wembley is on track for later in Q1/24 and is expected to result in an incremental 1,600 boe/d(23) of liquids and gas handling capacity for Tamarack operated and controlled volumes. Some associated downtime at the battery is expected during the first quarter to accommodate the expansion work.

In 2023, the Company added 11.0 net sections of land through acquisition at crown sales, further increasing the inventory depth of Tamarack's Charlie Lake asset.

Clearwater

West Marten Hills and Nipisi

At year-end 2023, Tamarack had brought 39 wells on production through the 15-15-076-05W5 battery, with December 2023 throughput at ~7,000 bbl/d (including nine C sand producers and 30 B sand producers). The success demonstrated by Tamarack's development in the 'B' and 'C' sands provides the ability to generate further capital efficiencies given the stacked nature of the play. Oil production from the north Clearwater assets averaged ~19,000 bbl/d exiting 2023, representing a YoY increase of ~40%.

- ***West Marten C Sand Success*** – At the Company's 02-22-076-05W5 and 12-22-076-05W5 pads the eight C sand wells had average peak monthly rates of 212 bbl/d per well. Based on this success, Tamarack drilled four additional C sand wells off the 08-15-076-05W5 pad which are currently cleaning up. As part of the 2024 program the Company expects to drill additional 'C' sand wells, building further on the results demonstrated to date.
- ***West Marten B Sand Performance Strength*** – Results from Tamarack's 30 'B' sand wells demonstrated peak monthly average rates of 270 bbl/d per well. These well results further emphasize the significant upside in the area, with the ability to leverage shared infrastructure to improve economic returns. In 2024, Tamarack is following up this success with seven additional 'B' sand wells at the 05-15-076-05W5 and 12-15-076-05W5 pads.
- ***Advancing Key Infrastructure*** – Tamarack's 10-02-077-05W5 Marten Creek Gas Plant came online in January 2024, flowing in excess of 3 MMcf/d at the inlet, delivering on the Company's gas conservation initiatives.

Marten Hills

As development is ongoing at Marten Hills, Tamarack is leveraging primary well cost efficiency improvements in conjunction with progressing waterflood. Tamarack brought 12 wells on-stream in August 2023 from the 09-06-075-25W4 pad. In aggregate these wells were drilled at a cost of under $100/metre representing an improvement of 12-15% relative to 2023 average budgeted cost.

Waterflood - Increasing Injection at Nipisi and Marten Hills

Four additional Nipisi injectors have been brought on-stream increasing Tamarack's total area water injection to >3,000 bbl/d, with plans to further ramp to >7,500 bbl/d by year-end 2024. At Marten Hills, Tamarack converted one additional injector bringing area water injection to >2,000 bbl/d. This area is also expected to ramp to >7,500 bbl/d by year-end 2024. Tamarack currently has 2,200 bopd, or 6% of Clearwater oil production under waterflood.

Delineation and Exploration

- ***West Nipisi*** – Since the beginning of 2023, Tamarack has drilled or participated in nine gross (4.7 net) wells in the West Nipisi area with greater than 30 days of production data. This includes five gross 'B' sand wells with average peak monthly rates of ~200 bbl/d per well, and four gross 'C' sand wells with average peak monthly rates of ~270 bbl/d per well, including the most recent 102/4-35-76-9W5 well which delivered an IP30 oil rate of 330 bbl/d. Based on this success, the Company plans to be active on its joint venture lands in the area in 2024.
- ***Seal*** – In Q1/23 Tamarack successfully drilled and tested three separate Clearwater equivalent sands off one pad (upper, middle, and lower). The combined IP30 from the three wells was approximately 380 bopd. The lowermost sand was drilled with only three legs, with the objective being to test commerciality of the sand. The middle and upper sands were developed with 6-leg lateral legs per sand, each extending approximately 1.25 miles in length. Based on the results of the Seal program Tamarack was able to derisk 950 MMbbl of OOIP on its existing lands. Given the stacked nature of the multiple zones, management expects development at Seal to drive strong capital efficiencies and economics with large-scale multi-well pads pushing lateral lengths to 1.5 miles.

Risk Management

The Company takes a systematic approach to manage commodity price risk and volatility to ensure sustaining capital, debt servicing requirements and the base dividend are protected through a prudent hedging management program. For 2024, approximately ~50% of net after royalty oil production is hedged against WTI with an average floor price of ~US$68/bbl with structures that allow for upside price participation averaging ~US$89/bbl. Our strategy provides protection to the downside while maximizing upside exposure. Additional details of the current hedges in place can be found in the corporate presentation on the Company website (www.tamarackvalley.ca).

We would like to thank our employees, shareholders and other stakeholders for all of their support over the past year. Tamarack materially advanced our multi-year transformation and would not have been able to achieve this without the dedication and hard work of our employees. We look forward to continuing to develop our high-quality assets to create shareholder value in a sustainable and responsible way.

Executive Update

Tamarack is pleased to announce the promotion of Rocky Baker to Vice President, Marketing. Since joining the Company in January 2022 Rocky has been instrumental in establishing a strong internal marketing team and executing on key initiatives to enhance both market access and product realizations. Rocky brings over 17 years of oil and gas marketing experience, and prior to joining Tamarack she was Manager of the Commercial Services Group at Inter Pipeline. Rocky holds a Chartered Professional Accounting (CPA) Designation and a Bachelor of Commerce degree from the University of Calgary.

Investor Call

9:30 AM MDT (11:30 AM EDT)

Tamarack will host a webcast at 9:30 AM MDT (11:30 AM EDT) on Wednesday, February 28, 2024 to discuss the year-end reserves, financial results and an operational update. Participants can access the live webcast via this link or through links provided on the Company's website. A recorded archive of the webcast will be available on the Company's website following the live webcast.

2023 Independent Qualified Reserve Evaluations

The following tables highlight the findings of the Reserve Reports, which have been prepared in accordance with definitions, standards and procedures contained in *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**") by McDaniel and GLJ, qualified independent reserves evaluators, each with an effective date of December 31, 2023 and preparation dates of February 9, 2024 and January 29, 2024, respectively. 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. All per share reserves metrics below are based on basic shares outstanding as of December 31, 2023. Note that columns may not add due to rounding.

Company Reserves Data (Forecast Prices and Costs)[11]

Reserves Category	Crude Oil Lt. & Med. Gross[24] (MBbl)	Crude Oil Lt. & Med. Net[24] (MBbl)	Crude Oil Heavy Gross (MBbl)	Crude Oil Heavy Net (MBbl)	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Natural Gas Liquids Gross[25] (MBbl)	Natural Gas Liquids Net[25] (MBbl)	Total Gross (MBoe)	Total Net (Mboe)
Proved:										
Developed Producing	19,543	15,120	31,980	25,968	58,966	53,063	2,535	2,008	63,886	51,940
Developed Non-Producing	761	626	925	783	2,972	2,684	124	100	2,305	1,956
Undeveloped	21,732	17,350	29,120	25,018	50,108	44,853	2,436	1,987	61,638	51,830
Total Proved	42,036	33,095	62,025	51,769	112,046	100,599	5,095	4,095	127,830	105,726
Probable	34,979	26,535	42,343	34,226	88,822	78,204	4,322	3,329	96,448	77,125
Total Proved plus Probable	77,015	59,631	104,368	85,995	200,869	178,803	9,417	7,424	224,277	182,850

Net Present Values of Future Net Revenue before Income Taxes Discounted at (% per year)[14]

Reserves Category	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)	Unit Value Before Tax Discounted at 10%/Year[27] ($/Boe)	Unit Value Before Tax Discounted at 10%/Year[27] ($/Mcfe)
Proved:							
Developed Producing	1,915,227	1,756,306	1,612,768	1,489,731	1,385,572	31.05	5.18
Developed Non-Producing	78,434	70,010	62,854	56,973	52,156	32.14	5.36
Undeveloped	1,498,597	1,146,822	886,756	693,236	546,929	17.11	2.85
Total Proved	3,492,258	2,973,138	2,562,378	2,239,940	1,984,657	24.24	4.04
Probable	3,477,826	2,526,987	1,913,213	1,501,457	1,213,948	24.81	4.13
Total Proved plus Probable	6,970,084	5,500,125	4,475,591	3,741,397	3,198,605	24.48	4.08

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs[14]

	Total Proved (Mboe)	Total Probable (Mboe)	Total Proved + Probable (Mboe)
December 31, 2022	135,066	107,126	242,192
Discoveries	–	–	–
Extensions & Improved Recovery[26]	31,003	13,887	44,890
Technical Revisions	10,470	(8,318)	2,152
Acquisitions	66	12	79
Dispositions	(24,484)	(16,323)	(40,807)
Economic Factors	175	64	239
Production	(24,467)	–	(24,467)
December 31, 2023	127,830	96,448	224,277

Future Development Capital Costs[28]

The following is a summary of estimated FDC required to bring TP and TPP undeveloped reserves on production.

Year	Total Proved Reserves ($000)	Total Proved Plus Probable Reserves ($000)
2024	378,357	402,127
2025	373,725	434,705
2026	296,491	410,352
2027 and Subsequent	194,631	626,325
Total	1,243,205	1,873,509
10% Discounted	1,060,652	1,525,973

Finding, Development & Acquisition Costs

	2023		Three-Year Average	
(amounts in $000s except as noted)	TP	TPP	TP	TPP
FD&A costs, including FDC[28][29]				
Exploration and development capital expenditures[30][31]	512,955	512,955	364,411	364,411
Acquisitions, net of dispositions[32]	(120,477)	(120,477)	792,303	792,303
Total change in FDC	244,820	286,099	298,385	412,050
Total FD&A capital, including change in FDC	**637,298**	**678,578**	**1,455,099**	**1,568,765**
Reserve additions, including revisions – Mboe[33]	41,648	47,281	24,125	25,942
Acquisitions, net of dispositions – Mboe[33]	(24,417)	(40,728)	15,440	29,996
Total FD&A Reserves[33]	**17,231**	**6,553**	**39,565**	**55,937**
F&D costs, including FDC - $/boe	20.90	20.86	22.47	22.46
Acquisition costs, net of dispositions - $/boe	9.55	7.55	59.14	32.88
FD&A costs, including FDC - $/boe	36.99	103.55	36.78	28.05

About Tamarack Valley Energy Ltd.

Tamarack is an oil and gas exploration and production company committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily on Charlie Lake and Clearwater plays in Alberta while also pursuing EOR upside in these core areas. Operating as a responsible corporate citizen is a key focus to ensure we deliver on our environmental, social and governance (ESG) commitments and goals. For more information, please visit the Company's website at www.tamarackvalley.ca.

Abbreviations

AECO	the natural gas storage facility located at Suffield, Alberta connected to TC Energy's Alberta System
ARO	asset retirement obligation; may also be referred to as decommissioning obligation
bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
CGU	cash generating unit
DCET	drilling, completions, equip and tie-in costs
EOR	enhanced oil recovery
GJ	gigajoule
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
IP30	average production for the first 30 days that a well is onstream
Mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MM	Million
MMcf/d	million cubic feet per day
MSW	Mixed sweet blend, the benchmark for conventionally produced light sweet crude oil in Western Canada
NGL	Natural gas liquids
OOIP	original oil in place
WCS	Western Canadian select, the benchmark for conventional and oil sands heavy production at Hardisty in Western Canada
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade

Reader Advisories

Notes to Press Release

1) See “Specified Financial Measures”
2) Annual average production from net dispositions of 6,400 boe/d comprised of 1,510 bbl/d light and medium oil, 1,310 bbl/d NGL and 21,500 mcf/d natural gas. Reserves associated with the net dispositions include:

	PDP	TP	TPP
Light & Medium Oil (Mbbl)	4,167	5,907	9,377
NGL (Mbbl)	3,731	4,867	8,219
Natural Gas (MMcf)	59,241	82,258	139,268
Total (Mboe)	17,772	24,484	40,807

3) Production of 67,034 boe/d comprised of 16,326 bbl/d light and medium oil, 35,788 bbl/d heavy oil, 3,536 bbl/d NGL and 68,302 mcf/d natural gas.
4) Production of 64,881 boe/d comprised of 14,928 bbl/d light and medium oil, 37,447 bbl/d heavy oil, 2,769 bbl/d NGL and 58,419 mcf/d natural gas.
5) Production impacts of approximately 4,500 boe/d comprised of 1,098 bbl/d light and medium oil, 922 bbl/d NGL and 14,880 mcf/d natural gas.
6) Free NOI is calculated as the asset level field operating netback less annual capital expenditures.
7) Utilizing a 10% discount 3-Consultant Average Forecast Pricing as detailed in the Company’s AIF.
8) PDP reserves of 64 MMboe comprised of 20 MMbbl light and medium oil, 32.0 MMbbl heavy oil, 3 MMbbl NGL and 59 MMcf natural gas.
9) TP reserves of 128 MMboe comprised of 42 MMbbl light and medium oil, 62 MMbbl heavy oil, 5 MMbbl NGL and 112 MMcf natural gas.
10) TPP reserves of 224 MMboe comprised of 77 MMbbl light and medium oil, 104 MMbbl heavy oil, 9 MMbbl NGL and 201 MMcf natural gas.
11) Based on the 3-Consultant (represented by: GLJ, Sproule Associates Limited and McDaniel) Average Forecast Pricing as detailed in the Company’s AIF.
12) The estimate of Contingent Resources has not been adjusted for risk based on the chance of development. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. See “*Resource Disclosure”*.
13) The estimate of Prospective Resources has not been adjusted for risk based on the chance of discovery or the chance of development. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not evaluated for economics. See “*Resource Disclosure”*.
14) Based on the 3-Consultant Average Forecast Pricing as at January 1, 2024
15) Based on the 3-Consultant Average Forecast Pricing as at January 1, 2023
16) Production of 61,000 – 63,000 boe/d comprised of 12,800-13,200 bbl/d light and medium oil, 36,600-37,800 bbl/d heavy oil, 2,400-2,500 bbl/d NGL and 54,900-56,700 mcf/d natural gas
17) Annual guidance numbers are based on 2024 average pricing assumptions of:

2024 Budget Pricing	
Crude Oil – WTI ($US/bbl)	$75.00
Crude Oil – MSW Differential ($US/bbl)	($4.00)
Crude Oil – WCS Differential ($US/bbl)	($17.00)
Natural Gas – AECO ($CAD/GJ)	$2.50
Foreign Exchange – CAD/USD	1.3450

18) Capital budget includes exploration and development capital, ESG initiatives, facilities land and seismic but excludes ARO, capital associated with the CIP and asset acquisitions and dispositions.
19) The Company’s acquisitions in 2022 and a more stringent emissions regulatory framework increased taxable emissions in 2023 and 2024. Carbon tax of $0.50-$1.00/boe is anticipated in 2024, a significant increase from 2023 as the price of carbon escalates 23% to $80/tonne and the emissions intensity benchmark tightens. Carbon tax was previously included in net production costs but will be reported separately going forward. Tamarack’s gas conservation initiatives that continue into 2024 are expected to substantively decrease the carbon tax burden in 2025 and subsequent years.
20) G&A noted excludes the effect of cash settled stock-based compensation.
21) Tamarack estimates a tax rate on funds flow of 9%-11%.

22) Production of 1,400 boe/d comprised of 1,000 bbl/d light and medium oil, 70 bbl/d NGL and 1,940 mcf/d natural gas.
23) Capacity increase of approximately 1,600 boe/d comprised of 546 bbl/d light and medium oil, 172 bbl/d NGL and 5,290 mcf/d natural gas.
24) Immaterial Tight Oil volumes have been included with light & medium crude oil volumes.
25) Condensate volumes have been included with natural gas liquids.
26) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery".
27) Unit values are based on Company net reserves.
28) FDC as per Reserve Report based on the 3-Consultant Average Forecast Pricing
29) While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of finding and development costs, FD&A costs have been presented because acquisitions and dispositions can have a significant impact on the Company's ongoing reserve replacement costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. Finding and development costs both including and excluding acquisitions and dispositions have been presented above.
30) The calculation of FD&A costs incorporates 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.
31) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
32) Includes 2022 and 2023 capital related to major land acquisitions in the Peavine and Seal areas.
33) Reserves are Company Gross Reserves which exclude royalty volumes.

Disclosure of Oil and Gas Information

Unit Cost Calculation. For the purpose of calculating unit costs, natural gas volumes have been converted to a boe using six thousand cubic feet equal to one barrel unless otherwise stated. A boe conversion ratio of 6:1 is based 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.

References in this press 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 press release comprise pentane, butane, propane, and ethane, being all NGL as defined by NI 51-101. References to "natural gas" throughout this press release refers to conventional natural gas as defined by NI 51-101.

The term original oil in place (OOIP) is equivalent to total petroleum initially in place ("TPIIP"). TPIIP, as defined in the COGEH, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered. OOIP disclosed herein was internally estimated by the Company's internal qualified reserves evaluator ("QRE") and prepared in accordance with NI 51-101 and the COGE Handbook. "Internally estimated" means an estimate that is derived by the Company's internal QRE and prepared in accordance with NI 51-101. Internal estimates contained in this press release were prepared effective as of January 1, 2024.

References in this press release to peak rates, initial production rates, IP30 and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Tamarack. The Company cautions that such results should be considered to be preliminary.

Reserves and Future Net Revenue Disclosure. All reserves values, future net revenue and ancillary information contained in this press release are derived from the Reserve Reports unless otherwise noted. All reserve references in this press release are "Company gross reserves". Company gross reserves are the Company's total working interest reserves before the deduction of any royalties payable by the Company. 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 GLJ and 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 and presented on a consolidated basis.

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 press release but not defined are defined in NI 51-101, CSA Staff Notice 51-324 – Revised Glossary to NI 51-101, Revised Glossary to NI 51-101, Standards of Disclosure for Oil and Gas Activities ("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.

Resource 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, 2023 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 28, 2024, 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 bitumen 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 press 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.

Oil and Gas Metrics. This press 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 press 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.

"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 press release, should not be relied upon for investment or other purposes.

Forward Looking Information

This press 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 “guidance”, “outlook”, “anticipate”, “target”, “plan”, “continue”, “intend”, “consider”, “estimate”, “expect”, “may”, “will”, “should”, “could” or similar words suggesting future outcomes. More particularly, this press release contains statements concerning: Tamarack’s business strategy, objectives, strength and focus, including the Company’s five-year plan; future consolidation activity, organic growth and development and portfolio rationalization; the Company's exploration and development plans and strategies; future intentions with respect to debt repayment and reduction and the Company's ROC framework, including enhanced dividends and share buybacks; the Company’s plans to reduce H1 2024 spending in an equivalent amount to Tamarack’s acceleration of 2024 spending; oil and natural gas production levels, adjusted funds flow and free funds flow; anticipated operational results for 2024 including, but not limited to, estimated or anticipated production levels (including in respect of Tamarack’s 2024 production guidance, which is maintained at the 61,000 to 63,000 boe/d range), capital expenditures, drilling plans and infrastructure initiatives, including on-stream timing of the new CSV Albright sour gas plant in the Charlie Lake and the expansion o the Wembley gas plant and anticipated margin improvements; the Company’s capital program, guidance and two-phase budget for 2024 and the funding thereof; expectations regarding commodity prices; the performance characteristics of the Company’s oil and natural gas properties; decline rates and EOR, including waterflood initiatives and long term net asset value capture; the continued successful integration of acquired assets; the ability of the Company to achieve drilling success consistent with management’s expectations, including leveraging the “Fan” well design; risk management activities; ARO reduction; risk management activities, including hedging positions and targets; Tamarack's continued capital flexibility under its 2024 capital program and expectation that this will not impact 2024 production guidance; Tamarack's commitment to ESG principles and sustainability, including gas conservation projects, emissions reductions and carbon tax savings; and the source of funding for the Company's activities including development costs. 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 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 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. In addition, statements related to "reserves", "contingent resources" and "prospective resources" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the resources can be discovered and profitably produced in the future.

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; the timing of and success of future drilling, development and completion activities; the geological characteristics of Tamarack's properties; the continued successful integration of acquired assets into Tamarack's operations; prevailing commodity prices, price volatility, price differentials and the actual prices received for the Company's products; the availability and performance of drilling rigs, facilities, pipelines and other oilfield services, including TMX expansion onstream timing; the timing of past operations and activities in the planned areas of focus; the drilling, completion and tie-in of wells being completed as planned; the performance of new and existing wells; the application of existing drilling and fracturing techniques; 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, maintaining 2024 guidance and resumption of operations; risks with respect to unplanned third-party pipeline outages; the risk that future dividend payments thereunder are reduced, suspended or cancelled; unforeseen difficulties in integrating of recently acquired assets into Tamarack's operations; incorrect assessments of the value of benefits to be obtained from acquisitions and 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); commodity prices, including the impact of the actions of OPEC and OPEC+ members; 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 between Russia and Ukraine and the recent crisis in Israel and Gaza 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 AIF for the year ended December 31, 2023 and the MD&A for the period ended December 31, 2023 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 press 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 forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about generating sustainable long-term growth in free funds, dividends and share buybacks, prospective results of operations and production (including annual average production, average oil & NGL weighting), oil weightings, hedging, operating costs, 2024 capital guidance, 2024 annual base budget guidance and budget pricing, 2024 two-phase capital budget and expenditures, decline rates, 2024 carbon tax, recycle ratios, balance sheet strength, adjusted funds flow and free funds flow, net debt, debt repayments, total returns 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 forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in Tamarack's guidance. The Company's actual results may differ materially from these estimates.

Specified Financial Measures

This press 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.

"Adjusted funds flow (capital management measure)" is calculated by taking cash-flow from operating activities, on a periodic basis, deducting current income tax expense and interest expense (excluding fees) and adding back income tax paid, interest paid, changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs settled during the applicable period. since Tamarack believes the timing of collection, payment or incurrence of these items is variable. 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.

"**Free funds flow** (capital management measure)" is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

"Free funds flow breakeven (capital management measure)" (previously referred to as "free adjusted funds flow breakeven") is determined by calculating the minimum WTI price in US/bbl required to generate free funds flow equal to zero, sustaining current production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability.

"Net debt (capital management measure)" is calculated as credit facilities plus senior unsecured notes, plus deferred acquisition payment notes, plus working capital surplus or deficiency, plus other liability, including the fair value of cross-currency swaps, plus government loans, plus facilities acquisition payments, less notes receivable and excluding the current portion of fair value of financial instruments, decommissioning obligations, lease liabilities and the cash award incentive plan liability.

"**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 the 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.

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

For additional information, please contact:

Brian Schmidt
President & Chief Executive Officer
Tamarack Valley Energy Ltd.
Phone: 403.263.4440
www.tamarackvalley.ca

Steve Buytels
Chief Financial Officer
Tamarack Valley Energy Ltd.
Phone: 403.263.4440
www.tamarackvalley.ca

Christine Ezinga
VP Business Development & Sustainability
Tamarack Valley Energy Ltd.
Phone: 403.263.4440
www.tamarackvalley.ca