tamarack valley ENERGY

TSX: TVE

Tamarack Valley Energy Ltd. Announces Year End 2021 Reserves and Fourth Quarter Highlights

Calgary, Alberta – January 31, 2022 – Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is pleased to announce certain unaudited financial and operating results for the three months and year ended December 31, 2021 and the results of Tamarack's year end independent oil and gas reserves evaluation as of December 31, 2021 (the "GLJ Report"), prepared by Tamarack's independent qualified reserves evaluator, GLJ Ltd. ("GLJ"). Selected reserves information is outlined below. The Company anticipates announcing its fourth quarter and audited year end 2021 financial results and filing an annual information form ("AIF") for the year ended December 31, 2021, on or near March 3, 2022.

Brian Schmidt, President and Chief Executive Officer of Tamarack commented, "2021 was a transformational year for Tamarack as we advanced our strategy of driving long term sustainable free funds flow(1) growth forward with the repositioning and further consolidation of the Company in the Charlie Lake and Clearwater oil plays. These plays complement our highly economic waterflood assets. Operationally, we exceeded our full year guidance and successfully integrated the assets into our portfolio, which is demonstrated in our robust reserves metrics including our low finding and development ("F&D") costs and strong recycle ratios."

Strong Fourth Quarter and Full Year 2021 Results

The following are unaudited highlights, and all numbers are approximate. During the quarter and year ended December 31, 2021, Tamarack:

- Achieved fourth quarter average production of 40,384 boe/d(2), driving full year production of approximately 34,562 boe/d(3) which is above our full year guidance range of 34,250 boe/d(4), despite the extreme cold weather impacts that hampered December production across the basin;
- Increased our oil and natural gas liquids ("NGL") weighting to 69% for both the fourth quarter and full year average 2021;
- Executed a capital program of $41.7 million for the fourth quarter and a total of $191.2 million for 2021, which was higher than our forecast due to the continued consolidation of Clearwater and Charlie Lake land positions through land sales during the quarter as well as the acceleration of approximately $9 million of first quarter 2022 capital into fourth quarter 2021 to ensure access to services in a timely and cost-efficient manner;
- Achieved adjusted funds flow(1) of $124 million for the quarter and $340 million for the year and generated $82 million and $149 million of free funds flow(1), excluding acquisitions, for the fourth quarter and full year 2021, respectively;
- Achieved operating netbacks(1), excluding the impacts of hedging, of $44.87/boe and $36.51/boe for the fourth quarter and full year 2021, respectively;
- Further consolidated our Charlie Lake position through two tuck-in acquisitions during the quarter; and
- Exited the quarter with $463.0 million in net debt(1).

2021 Reserve Highlights

Tamarack is pleased to provide select highlights of the Company's proved developed producing ("PDP"), total proved ("TP") and total proved plus probable ("TPP") reserves from the GLJ Report below. Finding, development and acquisition ("FD&A") costs and F&D costs contained within this press release include changes in future development capital ("FDC"). In addition to the summary information disclosed in this press release, more detailed information regarding Tamarack oil and gas reserves will be included in the AIF to be filed on SEDAR (www.sedar.com). The Company's reserves as presented in the GLJ Report do not include reserves associated with the previously announced planned acquisition of Crestwynd Exploration Ltd. ("**Crestwynd**") given such acquisition has yet to close. The ongoing positive impact of Tamarack's drilling program combined with Clearwater and Charlie Lake asset acquisitions contributed significantly to the reserves in 2021, further enhancing the long-term resiliency and sustainability of free funds flow(1) for the Company moving forward.

- Relative to year-end 2020, Tamarack increased PDP reserves 39% to 56.3 MMboe, TP reserves 63% to 104.1 MMboe and TPP reserves 64% to 181.9 MMboe in 2021.
- Replaced 225% of total 2021 production on a PDP basis, 419% on a TP basis and 661% on a TPP basis. PDP reserves represent 54% and 31% of TP and TPP reserves, respectively.
- Achieved 2021 PDP F&D costs of $14.38/boe, including changes in FDC, TP F&D costs of $14.66/boe and TPP F&D costs of $8.74/boe. These F&D metrics yielded reserve recycle ratios of 3.1x, 3.1x and 5.1x, respectively based on a Q4/21 operating netback(1). Based on a full year 2021 operating netback(1) the PDP, TP and TPP recycle ratios were 2.5x, 2.5x and 4.2x respectively.
- Achieved PDP FD&A costs of $32.68/boe including changes in FDC, TP FD&A costs of $22.79/boe and TPP FD&A costs of $15.10/boe. The TPP FD&A recycle ratio was 2.4x based on a full year 2021 corporate operating field netback(1).
- Before-tax net present value ("NPV") of reserves, discounted at 10% ("NPV10"), was $1.0 billion on a PDP basis, $1.7 billion on a TP basis and $3.0 billion on a TPP basis evaluated using three independent reserve evaluators average forecast pricing and foreign exchange rates as at January 2022.

2021 Independent Qualified Reserve Evaluation

The following tables highlight the findings of the GLJ Report, which has 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"). 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 & Associates Consultants Ltd (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, 2021.

Reserves Snapshot by Category:

	PDP	TP	TPP
Total Reserves (mboe)[1]	56,290	104,133	181,932
Reserves Added[2] (mboe)	28,398	52,908	83,375
Reserves Replacement	225%	419%	661%
NPV10 Before Tax ($mm)	$1,009	$1,675	$2,953

Notes:
(1) Total reserves are Company Gross Reserves which exclude royalty volumes
(2) Reserves Added takes the difference in reserves year-over-year plus the production for the year

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

(mboe)	December 31, 2021 [1]	December 31, 2020 [1]	% Change
PDP	56,290	40,507	39%
TP	104,133	63,840	63%
TPP	181,932	111,172	64%

Note:
(1) Total reserves are Company Gross Reserves which exclude royalty volumes

FD&A Costs

	PDP	TP	TPP
FD&A Cost per boe[1]	32.68	22.79	15.10
F&D Cost per boe[1]	14.38	14.66	8.74

Notes:
(1) 2021; including changes in FDC

Company Reserves Data (Forecast Prices and Costs)

	LIGHT & MEDIUM CRUDE OIL[1]		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:										
Developed Producing	26,322	21,496	4,093	3,487	114,981	104,619	6,712	5,551	56,290	47,971
Developed Non-Producing	1,242	1,089	0	0	5,053	4,567	255	200	2,339	2,051
Undeveloped	25,690	21,568	4,188	3,765	69,461	63,461	4,049	3,385	45,504	39,295
TOTAL PROVED	**53,253**	**44,153**	**8,281**	**7,252**	**189,495**	**172,647**	**11,016**	**9,136**	**104,133**	**89,316**
PROBABLE	40,856	32,806	7,819	6,644	128,681	117,187	7,677	6,232	77,799	65,214
TOTAL PROVED PLUS PROBABLE	**94,110**	**76,960**	**16,100**	**13,896**	**318,177**	**289,833**	**18,692**	**15,369**	**181,932**	**154,531**

Notes:
(1) Tight oil included in the light & medium crude oil product type represents less than 5.0% of any reserves category
(2) Conventional natural gas amounts include coal bed methane, in amounts less than 0.3% of any reserves category
(3) Columns may not add due to rounding

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

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% Per Year[1] ($/Boe)
PROVED:						
Developed Producing	1,261,988	1,121,358	1,008,539	919,330	847,794	21.02
Developed Non-Producing	58,418	48,404	40,960	35,369	31,072	19.97
Undeveloped	1,045,941	799,826	625,970	500,594	407,702	15.93
TOTAL PROVED	2,366,347	1,969,587	1,675,469	1,455,293	1,286,568	18.76
PROBABLE	2,344,259	1,677,816	1,278,008	1,019,532	841,347	19.60
TOTAL PROVED PLUS PROBABLE	4,710,606	3,647,403	2,953,476	2,474,825	2,127,915	19.11

Notes:
(1) Unit values based on Company net interest reserves
(2) The prices used to estimate net present values are based on the 3-Consultant Average Forecast Pricing
(3) Columns may not add due to rounding

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs

	MBOE		
FACTORS	**TP**	**Probable**	**TPP**
December 31, 2020	**63,840**	**47,332**	**111,172**
Extensions and Improved Recovery[1]	13,969	11,440	25,409
Technical Revisions	(3,638)	(11,467)	(15,105)
Acquisitions	40,747	30,323	71,070
Dispositions	(550)	(217)	(767)
Economic Factors	2,380	389	2,768
Production	(12,615)	0	(12,615)
December 31, 2021	**104,133**	**77,799**	**181,932**

Notes:
(1) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery"
(2) Columns may not add due to rounding
(3) Company Gross Reserves exclude royalty volumes

Future Development Capital Costs

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

FDC[1]

(amounts in $000s)	**TP**	**TPP**
2022	161,379	190,710
2023	169,751	219,325
2024	178,018	241,292
2025 and Subsequent	114,366	314,299
Total Undiscounted FDC	**623,515**	**965,626**
Total Discounted FDC at 10% per year	**518,215**	**773,442**

Note:
(1) FDC as per GLJ Report based on the 3-Consultant Average Forecast Pricing

FD&A Costs

(amounts in $000s except as noted)	2021 TP	2021 TPP	Three-Year Average TP	Three-Year Average TPP
FD&A costs, including FDC[1][2]				
Exploration and development capital expenditures [3][4]	191,159	191,519	157,889	157,889
Acquisitions, net of dispositions[5]	739,205	739,205	277,478	277,478
Total change in FDC	275,464	328,268	80,643	88,475
Total FD&A capital, including change in FDC	1,205,828	1,258,632	516,010	523,842
Reserve additions, including revisions – Mboe	12,711	13,074	8,128	5,999
Acquisitions, net of dispositions[5] – Mboe	40,197	70,302	17,854	30,609
Total FD&A Reserves	52,908	83,376	25,982	36,608
F&D costs, including FDC - $/boe	14.66	8.74	16.33	14.71
Acquisition costs, net of dispositions - $/boe	25.36	16.28	21.47	14.23
FD&A costs, including FDC - $/boe	22.79	15.10	19.86	14.31

Notes:

(1) 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.
(2) 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.
(3) 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.
(4) The capital expenditures also exclude capitalized administration costs.
(5) Includes capital spent in 2021 to develop the assets acquired during 2021.
(6) Columns may not add due to rounding
(7) Calculations use Company Gross Reserves which exclude royalty volumes.

Crestwynd Acquisition Update

Further to the Company's previous announcement, Tamarack expects the previously announced acquisition of Crestwynd to close on or around February 15, 2022, subject to certain customary conditions. Tamarack has internally estimated the effect of the Crestwynd reserves, and has highlighted the following pro forma reserves and future values for the combined entities as at December 31, 2021.

Reserves Snapshot Pro Forma the Crestwynd Acquisition:

	PDP	TP	TPP
Total Tamarack Reserves (mboe)[1]	56,290	104,133	181,932
Total Crestwynd Reserves (mboe)[1][2]	1,902	6,320	9,650
Total Pro Forma Reserves (mboe)[1][2]	**58,192**	**110,453**	**191,582**
Tamarack NPV10 Before Tax ($mm)	$1,009	$1,675	$2,953
Crestwynd NPV10 Before Tax ($mm)[2]	$67	$149	$218
Proforma NPV10 Before Tax ($mm)[2]	**$1,076**	**$1,824**	**$3,171**

Notes:

(1) Total reserves are Company Gross Reserves which exclude royalty volumes.
(2) PDP reserves, TP reserves, TPP reserves and NPV10 Before Tax in respect of the Crestwynd assets have been internally estimated by the Company's internal Qualified Reserve Evaluators ("QRE") and prepared in accordance with NI 51-101 and COGEH effective as of December 31, 2021, using the 3-Consultant Average Pricing to estimate net present values. "Internally estimated" means an estimate that is derived by the Company's internal QRE and prepared in accordance with NI 51-101 and COGEH.

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, Clearwater and EOR plays in Alberta. 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
bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	gigajoule
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
MSW	Mixed sweet blend, the benchmark for conventionally produced light sweet crude oil 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 "Non-IFRS Measures"; free funds flow was previously referred to as free adjusted funds flow

(2) Comprised of 18,487 bbl/d light and medium crude oil, 5,616 bbl/d heavy crude oil, 3,899 bbl/d NGL and 74,297 mcf/d conventional natural gas.

(3) Comprised of 15,670 bbl/d light and medium crude oil, 4,613 bbl/d heavy crude oil, 3,408 bbl/d NGL and 65,226 mcf/d conventional natural gas.

(4) Comprised of 15,250-15,750 bbl/d light and medium crude oil, 4,800-5,000 bbl/d heavy crude oil, 3,300-3,500 bbl/d NGL and 64,000-65,000 mcf/d conventional natural gas.

Unaudited Financial Information

Certain financial and operating results included in this press release, including adjusted funds flow, free funds flow, operating netbacks, capital expenditures and production information, are based on unaudited estimated results. These estimated results are subject to change upon completion of the Company's audited financial statements for the year ended December 31, 2021, and changes could be material. Tamarack anticipates filing its audited financial statements and related management's discussion and analysis for the year ended December 31, 2021 on or near March 3, 2022.

Disclosure of Oil and Gas Information

AIF. Tamarack's Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1 dated effective as at December 31, 2021, which will include further disclosure of Tamarack's oil and gas reserves and other oil and gas information (excluding in respect of the assets to be acquired pursuant to Tamarack's previously announced acquisition of Crestwynd) in accordance with NI 51-101 and COGEH forming the basis of this press release, will be included in the AIF which will be available on SEDAR at www.sedar.com on or near March 3, 2022.

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 NI 51-101. Boe may be misleading, particularly if used in isolation.

Reserves and Future Net Revenue Disclosure. All reserves values, future net revenue and ancillary information contained in this press release are derived from the GLJ Report 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 in evaluating Tamarack's reserves or by the QRE in evaluating Crestwynd's reserves will be attained and variances could be material. All reserves assigned in the GLJ Report are located in the Provinces of Alberta and Saskatchewan 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 Tamarack's and Crestwynd's, as applicable, 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.

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, recycle ratio, operating netback and reserves replacement.

> "**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.
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> "**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.
>
> **"Operating Netback"** is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity, interest rate and foreign exchange derivative contracts, less royalties and net production and transportation costs.
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> **"Reserves replacement**" is calculated as reserves in the referenced category divided by estimated referenced production.

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; the acquisition of Crestwynd (the "Acquisition") and the timing thereof; future consolidation activity and organic growth; future intentions with respect to return of capital; oil and natural gas production levels, decline rates, adjusted funds flow, free funds flow; anticipated operational results for 2022 including, but not limited to, estimated or anticipated production levels, capital expenditures and drilling plans; expectations regarding commodity prices; the performance characteristics of the Company's oil and natural gas properties; the ability of the Company to achieve drilling success consistent with management's expectations; the source of funding for the Company's activities including development costs. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be 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, Crestwynd and the assets to be acquired pursuant to the Acquisition; the receipt of all approvals and satisfaction of all conditions to the completion of the Acquisition; the timing of and success of future drilling, development and completion activities; the geological characteristics of Tamarack's properties; the characteristics of recently acquired assets; the successful integration of recently 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; 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; 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: the risk that future dividend payments 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 (including the Acquisition); 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; the uncertainty of estimates and projections relating to production, cash generation, costs and expenses; health, safety, litigation and environmental risks; access to capital; and the COVID-19 pandemic. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to react to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Please refer to the annual information form for the year ended December 31, 2020, the management's discussion and analysis for the period ended September 30, 2021 (the "MD&A") and other continuous disclosure documents 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.sedar.com.

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 Tamarack's prospective results of operations and funds from operations, 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.

Non-IFRS Measures

Certain measures commonly used in the oil and natural gas industry referred to herein, including, "adjusted funds flow", "free funds flow", "operating netback" and "net debt", do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other companies. These non-IFRS measures are further described and defined below. Such non-IFRS measures are not intended to represent operating profits nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

"**Adjusted funds flow**" is calculated by taking cash-flow from operating activities and adding back changes in non-cash working capital and expenditures on decommissioning obligations and corporate transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating loss per share.

"**Free funds flow**" (previously referred to as "free adjusted funds flow") 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.

A reconciliation of adjusted funds flow to the most directly comparable measure calculated and presented in accordance with IFRS and a subsequent reconciliation of such adjusted funds flow to free funds flow is as follows:

(C$ thousands, unless otherwise noted)	Three months ended December 31, 2021 *(unaudited)*	Twelve months ended December 31, 2021 *(unaudited)*
Cash flow from operating activities	**118,647**	**297,894**
Abandonment expenditures	1,574	4,466
Transaction costs	-	8,110
Changes in non-cash working capital	3,859	29,789
Adjusted funds flow	**124,080**	**340,259**
Less: capital expenditures	41,672	191,159
Free Funds Flow	**82,408**	**149,100**

"**Operating Netback**" is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity, interest rate and foreign exchange derivative contracts, less royalties and net production and transportation costs. "**Operating Field Netback**" is calculated as total petroleum and natural gas sales, including interest rate and foreign exchange derivative contracts, less royalties and net production and transportation costs. A reconciliation of operating netback and operating field netback per boe to the most directly comparable measure calculated and presented in accordance with IFRS is as follows:

($/boe)	Three months ended December 31, 2021 *(unaudited)*	Twelve months ended December 31, 2021 *(unaudited)*
Average realized sales	65.21	55.38
Royalty expenses	(9.50)	(8.10)
Net production expenses	(9.16)	(9.15)
Transportation expense	(1.68)	(1.62)
Operating field netback	**44.87**	**36.51**
Realized commodity hedging gain (loss)	(8.25)	(6.40)
Operating netback	**36.62**	**30.11**

"**Net debt**" is calculated as bank debt plus working capital surplus or deficit, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities. The following outlines the Company's calculation of net debt:

(C$ thousands, unless otherwise noted)	Three months ended December 31, 2021 *(unaudited)*
Accounts payable and accrued liabilities	72,188
Cross currency swap liability	292
Accounts receivable	(78,804)
Prepaid expenses and deposits	(7,829)
Working capital deficiency (surplus)	(14,153)
Bank debt	477,437
Net debt	463,284

For additional information, please contact

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