Tamarack Valley Energy Ltd. Announces Record 2018 Financial and Operating Results Including 43% Increase in Total Adjusted Operating Field Netbacks, 20% Increase in Production and 22% Increase in Oil Reserves

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CALGARY, Feb. 27, 2019 - Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is pleased to announce its fir and operating results for the three and twelve months ended December 31, 2018 and the results of its independent oil a reserves evaluation as of December 31, 2018, prepared by GLJ Petroleum Consultants Ltd. ("GLJ"). Selected financia operational and reserves information is outlined below and should be read with Tamarack's audited consolidated financ statements ("Financial Statements"), management's discussion and analysis ("MD&A") as of December 31, 2018, which available on SEDAR at www.sedar.com and on Tamarack's website at www.tamarackvalley.ca. The Company's annua information form ("AIF") for the year ended December 31, 2018 will be filed on SEDAR and available on Tamarack's we close of business February 27, 2019.

2018 Financial and Operating Highlights

- Maintained stable production volumes of 24,780 boe/d in Q4/18 relative to 24,765 boe/d in Q3/18, while investing $25.8 million in capital expenditures, a $52.3 million reduction from the previous quarter.
- Total adjusted operating field netback (previously referred to as "adjusted funds flow"; see "Non-IFRS Measures") increased 43% in 2018 to $226.5 million ($0.99 per share basic and $0.97 per share diluted), from $158.4 million ($0.70 per share basic and diluted).
- In Q4/18, total adjusted operating field netback of $38.3 million exceeded capital spending of $21.0 million, net of acquisitions and dispositions, by $17.3 million, resulting in excess total adjusted operating field netback for the pe which was directed to debt repayment and continued funding of the Company's active share repurchase program
- Year over year, achieved a 20% increase in production, and an 8% increase in the oil and natural gas liquids ("NG weighting percentage, while spending $9 million less capital, after acquisitions and dispositions, than the mid-poir Company's previous capital guidance.
- Full year 2018 net production and transportation expenses per boe were 6% lower relative to 2017, stemming pri from increased production from the lower-cost Veteran area.
- Tamarack's continued increase in oil and liquids weighting through 2018 largely contributed to 16% higher operat netbacks (see "Non-IFRS Measures") compared to 2017, further supported by improved pricing and lower transp expenses per boe year over year.
- Invested $219.2 million in total capital expenditures net of dispositions during 2018, which included drilling a total (158.2 net) wells, comprised of 129 (124.7 net) Viking oil wells, 19 (17.8 net) Cardium oil wells, 4 (4.0 net) Penny 11 (10.7 net) Redwater oil wells, one exploratory vertical stratigraphic well and one (1.0 net) water source well.

2018 Reserve Highlights

- Tamarack's strategy to enhance value through increased oil weighting was evidenced by increases to the Compa crude oil reserves which grew by 22% for total proved plus probable ("TPP"), by 15% for total proved ("TP") and 1 proved developed producing ("PDP"), respectively, over 2017.

- Growth across all reserves categories on an absolute basis was achieved in 2018; increased TPP reserves by 11 101.6 million boe; increased TP reserves by 8% to 55.7 million boe; and increased PDP reserves by 2% to 31.8 r boe.
- On a per share basis (basic), realized growth of 12% in TPP, 9% in TP and 3% in PDP reserves, demonstrating Tamarack's continued focus on enhancing per share metrics.
- Net asset value based on the net present values (discounted at 10%) of the TP and TPP reserves is $2.83 and $5 basic share, respectively. The net present value of reserves has been adjusted for net debt of $179.9 million but a no value for undeveloped land or infrastructure.
- Achieved attractive capital efficiencies through the 2018 development program, generating a TPP finding and dev ("F&D") and finding, development and acquisition ("FD&A") cost recycle ratio of 2.4x and 2.5x, respectively, and a and FD&A cost recycle ratio of 1.5x and 1.6x based on the 2018 average operating field netback of $30.05/boe.
- Crude oil weighting across reserves categories also increased to 58%, 55% and 52% for TPP, TP and PDP, resp compared to 54%, 52% and 49% for the same categories in 2017, driving oil and NGL weighting across all reserv categories to approximately 65% compared to 62% in 2017.
- The Company replaced 144% of production on a TP basis and 214% on a TPP basis.
- Achieved TPP F&D costs of $12.59/boe and TPP FD&A costs of $11.85/boe, both including the change in future development capital ("FDC") contributing to reducing the realized three-year average TPP F&D costs to $15.10/b TPP FD&A costs to $16.75/boe, both including the change in FDC.
- Based on 2018 average production of 24,237 boe/d, achieved a TPP reserve life index of 11.5 years.

Financial & Operating Results

	Three months ended			Years ended		
	December 31,			December 31,		
	2018	2017	% change	2018	2017	% change
($ thousands, except per share)						
Total Revenue	73,075	90,160	(19)	398,804	283,672	41
Adjusted operating field netback [1]	38,346	57,583	(33)	226,475	158,383	43
Per share – basic [1]	$ 0.17	$ 0.25	(32)	$ 0.99	$ 0.70	41
Per share – diluted [1]	$ 0.17	$ 0.25	(32)	$ 0.97	$ 0.70	39
Net income (loss)	18,952	(12,525)	251	38,310	(13,924)	375
Per share – basic	$ 0.08	$ (0.05)	260	$ 0.17	$ (0.06)	383
Per share – diluted	$ 0.08	$ (0.05)	260	$ 0.16	$ (0.06)	367
Net debt [1]	(179,880)	(173,180)	4	(179,880)	(173,180)	4
Capital Expenditures [2]	25,798	35,516	(27)	226,251	192,302	18
Weighted average shares outstanding (thousands)						
Basic						

227,211

228,066

–

227,720

225,306

1

Diluted	232,066	228,066	2	233,561	225,306	4
Share Trading (thousands, except share price)						
High	$ 5.20	$ 3.15	65	$ 5.20	$ 3.59	45
Low	$ 1.81	$ 2.49	(27)	$ 1.81	$ 1.96	(8)
Trading volume (thousands)	72,410	35,006	107	268,916	196,595	37
Average daily production						
Light oil (bbls/d)	14,163	12,189	16	13,769	9,929	39
Heavy oil (bbls/d)	755	500	51	552	511	8
NGL (bbls/d)	1,485	1,459	2	1,398	1,547	(10)
Natural gas (mcf/d)	50,262	51,956	(3)	51,108	48,893	5
Total (boe/d)	24,780	22,807	9	24,237	20,136	20
Average sale prices						
Light oil ($/bbl)	36.78	65.08	(43)	64.17	59.42	8
Heavy oil ($/bbl)	49.33	48.97	1	59.13	46.01	29
NGL ($/bbl)	33.72	44.03	(23)	41.89	32.38	29
Natural gas ($/mcf)	3.70	1.89	96	2.30	2.32	(1)
Total ($/boe)	32.05	42.97	(25)	45.08	38.60	17
Operating netback ($/Boe) [1]						
Average realized sales	32.05	42.97	(25)	45.08	38.60	17
Royalty expenses	(2.59)	(4.03)	(36)	(4.51)	(3.96)	14
Production expenses	(10.47)	(10.40)	1	(10.52)	(11.19)	(6)
Operating field netback ($/Boe) [1]	18.99	28.54	(33)	30.05	23.45	28
Realized commodity hedging gain (loss)	0.04	1.53	(97)	(2.03)	0.77	(364)
Operating netback	19.03	30.07	(37)	28.02	24.22	16
Adjusted operating field netback ($/Boe) [1]	16.82	27.44	(39)	25.60	21.55	19

Notes:

(1) Net debt, operating netback, operating field netback and adjusted operating field netback do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. See "Oil and Gas Metrics" and "Non-IFRS Measures".

(2) Capital expenditures include exploration and development expenditures, but exclude asset acquisitions and dispositions.

2018 In Review

Through 2018, Tamarack delivered another year of exceptional performance supplemented by an unwavering commitm enhancing per share and debt-adjusted per share value. In each quarter, the Company met or exceeded expectations production while remaining focused on driving costs down and achieving strong capital efficiencies. Tamarack grew an production volumes 20% in 2018 over 2017, averaging 24,237 boe/d (65% oil and NGL), compared to 20,136 boe/d (6 and NGL) following a successful 2018 drilling program combined with strong capital efficiencies. The Company's 2018 annual production was at the mid-point of its 2018 average guidance range of 24,000 to 24,500 boe/d (66% oil and NG Q4/18, Tamarack achieved record production of 24,780 boe/d (66% oil and NGL) exceeding the Company's lower end 2018 guidance range of 24,500 to 25,000 boe/d.

Consistent with historical practices during periods of volatility in commodity prices, Tamarack remains disciplined in its capital allocation and preservation of balance sheet strength. This became critical during the final quarter of 2018 when an unexpected and extreme widening of Canadian crude oil price differentials severely reduced the Company's realized price for its oil and NGL products. In response to this, Tamarack elected to defer $7.4 million of the $28.4 million in capital spending that had previously been planned for acceleration from 2019 into Q4/18. As such, the Company's Q4/18 capital spending totaled $21.0 million net of acquisitions and dispositions, bringing its total 2018 capital investment to $226.3 million ($219.2 million including acquisitions, net of dispositions). Tamarack remains focused on drilling wells which are expected to payout in 1.5 years or less and estimates it has more than nine years of development within its current inventory.

During Q4/18, capital was directed to drill a total of 24 (23.2 net) Viking oil wells and one (1.0 net) water source well in t Veteran area. Of these Viking oil wells, 19 (18.5 net) are expected to be brought on production in Q1/19, while five (4.8 the drilled Viking oil wells were also completed, equipped and tied-in during the period. Six of the Viking wells are futur Veteran waterflood injection wells, which will produce to recover the capital costs until the commencement of the injecti project in the first half of 2019. In addition, Tamarack completed and brought on production 18 (17.8 net) Viking oil wel one (1.0 net) Penny oil well that had been drilled in late Q3/18.

Despite the weakness in realized oil prices during Q4/18, Tamarack generated total adjusted operating field netback of million ($0.17 per share basic and diluted), exceeding its capital spending, including acquisitions and net of dispositions $17.3 million for the quarter. The Company elected to direct excess total adjusted operating field netback to debt repay and continued funding of Tamarack's active normal course issuer bid ("NCIB"). For the full year 2018, adjusted operati netback totaled $226.5 million ($0.99 per basic share; $0.97 per diluted share), an increase of 43% over $158.4 million per basic and diluted share) in 2017. Based on the forward curve price deck, the Company anticipates generating exce adjusted operating field netback in 2019 to again fully fund its capital program, achieve 3-5% debt-adjusted production growth in Q4/19 over Q4/18 and have incremental funds remaining. With this situation and by maintaining financial flex Tamarack retains optionality to increase drilling activity, pursue tuck-in acquisitions, repay debt or continue share buyba under the NCIB depending on the prevailing price environment. Year-end 2018 net debt totaled $179.9 million, which represents a net debt to Q4/18 annualized adjusted operating field netback ratio of 1.2 times, compared to 0.8 times at December 31, 2017.

Tamarack's oil and NGL weighting continued to increase through 2018 and averaged 65%, compared to 60% in 2017, a largely contributed to operating field netbacks of $30.05/boe, 28% higher than in 2017. Tamarack's average per boe sa increased 17% year-over-year to $45.08/boe in 2018 from $38.60/boe in 2017 while net production and transportation e per boe declined by 6%. The Company anticipates its oil and NGL weighting will range between 64 to 66% of total 201 production.

During 2018, Tamarack purchased and cancelled 3,025,000 outstanding common shares under the NCIB program, for investment of $11.7 million. The NCIB provides management a tool that can be employed when there is a perceived misalignment between the Company's prevailing share price and the underlying current and future potential value of its In addition, it helps to offset the potential for dilutive impact that may be associated with the exercise and settlement of issued under Tamarack's stock-based compensation program. In addition to the NCIB, the Company purchased 1,803 outstanding common shares in the open market for $5.8 million, which are held in trust and used to settle RSUs upon fu exercise, further supporting Tamarack's per share metrics.

2018 Year-End Reserves Summary

Tamarack continued to generate attractive capital efficiency metrics in 2018, despite a very challenging Q4/18 crude oi environment which has had a severely negative impact on operating netbacks for the period. The Company's full year operating field netback was more representative of the performance through the year, averaging $30.05/boe, and reflec strategic capital shift to projects with higher oil and NGL weighting. Using the Company's full year operating field netba Tamarack generated a TPP F&D recycle ratio of 2.4x, 1.5x for TP, and 1.2x for PDP, and FD&A recycle ratios of 2.5x fo 1.6x for TP and 1.2x for PDP. The Company maintained a consistent approach to reserves booking, with TP reserves only 140.6 net Veteran and Consort horizontal Viking oil wells, 103.2 net Redwater and Saskatchewan horizontal Viking and 47.5 net undeveloped horizontal Cardium oil locations. Further, the FDC for 2019, within GLJ's 2018 reserves eval $126.8 million is materially lower than Tamarack's 2019 capital expenditure guidance of $170 to $180 million. The total a TP basis was $381.6 million and on a TPP basis was $700.2 million.

Consistent with Tamarack's core strategy, the Company continued to take a long-term approach to the allocation of cap development of its asset base in 2018, including the Veteran waterflood project. During the year, the Company investe million in waterflood capital, including constructing pipelines for the planned injectors, drilling a water source well, commencement of the water handling upgrades to the Veteran oil battery, drilling nine wells as future injectors in the Ve unit and drilling six wells to be converted into injectors in East Veteran in 2019. The results of this capital investment ha conservatively recognized, as GLJ assigned probable reserves of 4.9 million barrels of oil associated with the waterfloo no reserves yet reflected in the PDP or TP categories. Excluding waterflood capital from PDP and TP F&D costs (inclu FDC) results in $22.28/boe and $17.62/boe, respectively and generates recycle ratios of 1.3x and 1.7x for the same res categories. In 2019, Tamarack plans to invest an additional $20 million to further the waterflood project, which will bene Company in future years by improving oil recoveries, reducing corporate decline rates and increasing production rates while utilizing existing Tamarack-owned infrastructure.

The following tables highlight Tamarack's 2018 year-end independent reserves assessment and evaluation prepared b with an effective date of December 31, 2018 (the "GLJ Report"). The GLJ Report has been prepared in accordance wi definitions, standards and procedures contained in National Instrument 51-101 – Standards of Disclosure for Oil Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook. All evaluations and summaries of future n revenue are stated prior to provision for interest, debt service charges or general and administrative expenses and afte deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capita expenditures. The information included in the "Net Present Values of Future Net Revenue before Income Taxes" table based on an average of pricing assumptions prepared by three independent external reserves evaluators. It should not assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. Given Tamarack's ongoing and extensive share buy-backs during 2018 under its NCIB and shares held in tr settle future restricted share unit ("RSU") exercises, all per share reserves metrics below are based on basic shares outstanding.

Reserves Snapshot by Category:

	PDP	TP	TPP
Reserves Added[(1)] (mboe)	9,319	12,737	18,957
Total Reserves (mboe)[(2)]	31,788	55,651	101,572
Reserves Replacement	105%	144%	214%
NPV10 BT ($mm)	$515.9	$820.8	$1,524.4
FD&A Cost per boe[(3)]	$24.47	$18.83	$11.85
Recycle Ratio[(4)]	1.2x	1.6x	2.5x
F&D Cost per boe [(3)]	$25.74	$20.23	$12.59
Recycle Ratio[(4)]	1.2x	1.5x	2.4x

Notes:

(1) This number takes the difference in reserves year over year plus the production for the year.

(2) Total reserves are Company Gross Reserves which exclude royalty volumes.

(3) Including changes in FDC.

(4) Based on 2018 operating field netback of $30.05 per boe.

Reserves Data (Forecast Prices and Costs) – Company Gross

RESERVES CATEGORY	CRUDE OIL[1]		CONVENTIONAL NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED:								
Developed Producing	16,484	14,629	75,954	70,112	2,645	2,111	31,788	28,426
Developed Non-Producing	1,081	962	8,928	7,902	61	54	2,630	2,333
Undeveloped	12,976	11,698	40,281	37,585	1,543	1,399	21,233	19,361
TOTAL PROVED	30,542	27,290	125,163	115,600	4,249	3,564	55,651	50,120
PROBABLE	28,609	23,857	86,930	79,982	2,824	2,399	45,921	39,585
TOTAL PROVED PLUS PROBABLE	59,151	51,146	212,093	195,581	7,073	5,962	101,572	89,706

Notes:

(1) Heavy oil and tight oil included in the crude oil product type represents less than 3.1% of any reserves category and as such is immaterial.

(2) Conventional natural gas amounts include coal bed methane, in amounts less than 0.1%.

(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	681,815	590,082	515,863	459,947	416,912	18.15
Developed Non-Producing	55,510	44,239	37,438	32,842	29,474	16.05
Undeveloped	452,997	345,872	267,459	210,646	168,666	13.81
TOTAL PROVED	1,190,322	980,193	820,760	703,435	615,052	16.38
PROBABLE	1,407,444	962,460	703,627	540,753	431,402	17.77
TOTAL PROVED PLUS PROBABLE	2,597,765	1,942,653	1,524,387	1,244,188	1,046,454	16.99

Notes:

(1) Unit values based on Company net interest reserves.

(2) The prices used to estimate net present values are the average of those used by the largest independent industry reserve evaluators.

(3) Columns may not add due to rounding.

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs

	MBOE		
FACTORS	Proved	Probable	Proved + Probable
December 31, 2017	51,761	39,701	91,462
Extensions and Improved Recovery[1]	10,907	8,777	19,684
Technical Revisions	1,060	(2,875)	(1,816)
Acquisitions	1,128	527	1,655
Dispositions	0	0	0
Economic Factors	(358)	(210)	(567)
Production	(8,847)	0	(8,847)
December 31, 2018	55,651	45,921	101,572

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 future development capital required to bring proved and probable undeveloped reserves on production.

Future Development Capital[1]		
(amounts in $000s)	Total Proved	Total Proved + Probable
2019	91,721	126,768
2020	162,651	193,817
2021	87,219	156,685
2022 and Subsequent	39,978	222,902
Total Undiscounted FDC	381,570	700,174
Total Discounted FDC at 10% per year	323,279	563,488

Note:

(1) FDC as per GLJ independent reserve evaluation effective December 31, 2018 based on GLJ forecast pricing.

FD&A Costs	2018		Three Year Average	
(amounts in $000s except as noted)	TP	TPP	TP	TPP
FD&A costs, including FDC[1][2]				
Exploration and development capital expenditures [3][4]	216,584	216,584	155,144	155,144
Acquisitions, net of dispositions[5]	2,627	2,627	160,913	160,913
Total change in FDC	20,572	5,414	62,160	111,433
Total FD&A capital, including change in FDC	239,783	224,625	378,217	427,490
Reserve additions, including revisions – Mboe	11,609	17,302	8,364	12,010
Acquisitions, net of dispositions[5] – Mboe	1,128	1,655	8,505	13,509
Total FD&A Reserves	12,737	18,956	16,869	25,519
F&D costs, including FDC - $/boe	20.23	12.59	19.90	15.10
Acquisition costs, net of dispositions - $/boe	4.33	4.12	24.90	18.22
FD&A costs, including FDC - $/boe	18.83	11.85	22.42	16.75

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 2018 to develop the assets acquired during 2018.

(6) Columns may not add due to rounding.

(7) Calculations using Company Gross Reserves which exclude royalty volumes.

2019 Guidance

Our 2019 guidance remains unchanged with plans to invest between $170 and $180 million, funded entirely through adjusted operating field netback. This capital program is expected to result in production of 23,500 – 24,500 boe/d (64-66% oil and NGL). In the context of continued volatility in oil prices and supported by the Company's exceptional operational execution, Tamarack remains committed to investing in longer-term projects, including the Veteran waterflood, which the Company expects will reduce the overall corporate decline rate in 2020 and enhance Tamarack's sustainability.

Effective January 1, 2019 the Government of Alberta imposed production curtailments which, when combined with active production management and engagement from the producer community, have resulted in a significant narrowing of the differential into the early part of 2019. The Company remains well positioned to withstand further crude oil price volatility given approximately 30% of its 2019 production is protected with hedges that include a US$60.00/bbl WTI put option and another approximately 3% is protected with fixed price contracts at US$64.60/bbl. Regardless, the Company will continue to closely monitor current and future commodity prices and price differentials. While the Company's 2019 capital guidance assumes activity levels will be weighted evenly between H1 and H2 of 2019, the program timing for H1 has been designed to comply with the required production cuts. Following expected stable production levels in H1/19 due to the mandatory volume curtailments, Tamarack anticipates realizing a meaningful ramp-up in production volumes during the second half of 2019, assuming no additional government intervention.

The Company's 2019 guidance and assumptions are outlined below:

- Annual average production between 23,500 – 24,500 boe/d (64-66% oil and NGL), with 2019 exit producti estimated between 25,500 – 26,500 boe/d (64-66% oil and NGL);
- Capital expenditures between $170 to $180 million to maintain the Alberta government's mandatory production curtailments during Q1 of 2019;
- Estimated year end 2019 net debt to Q4 annualized adjusted operating field netback ratio of approximately 1.0 ti an estimated $100 million of liquidity on existing credit facilities; and
- Average 2019 commodity price assumptions of WTI US$50.00/bbl, Edmonton Par C$52.33/bbl, WTI / Edmonton differential of US$10.75/bbl, AECO $1.31/GJ and a Canadian/US dollar exchange rate of $0.75.

About Tamarack Valley Energy Ltd.

Tamarack is an oil and gas exploration and production company committed to long-term growth and the identification, evaluation and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack's strategic direction is focused on two key principles: (i) targeting repeatable and relatively predictable plays that provide long-life reserves; and (ii) using a rigorous, proven modeling process to carefully manage risk and identify opportunities. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily in the Cardium and Viking fairways in Alberta that are economic over a range of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its balance sheet.

Abbreviations

bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands barrels of oil equivalent
mcf	thousand cubic feet
GJ	gigajoule
MMcf	million cubic feet
Mbbls	thousand barrels
mcf/d	thousand cubic feet per day
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
AECO	the natural gas storage facility located at Suffield, Alberta connected to TransCanada's Alberta System
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board

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

Reserves Disclosure. All reserve references in this press release are "Company interest reserves". Company interest reserves are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable the Company. It should not be assumed that the present worth of estimated future cash flow presented herein represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Tamarack's 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.

Oil and Gas Metrics. This press release contains metrics commonly used in the oil and natural gas industry, such as operating field netback, operating netback, development capital, F&D costs, FD&A costs, recycle ratio, reserve life index and net asset value.

"Operating field netback" equals total petroleum and natural gas sales less royalties and operating costs calculated on a boe basis.

"Operating netback" is the operating field netback with realized gains and losses on commodity and foreign exchange derivative contracts.

"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 and also includes the cost of acquisitions and capital associated with acquisitions where reserve additions are attributed to the acquisitions.

"Finding and development 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.

"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.

"Reserve life index" is calculated as total Company interest reserves divided by annual production.

"Net asset value" is based on present value of future net revenues discounted at 10% before tax on reserves, net of estimated net debt at year end divided by the basic shares outstanding at year end.

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; operational execution and the ability of the Company to achieve drilling success consistent with management's expectations; commodity prices; market conditions impacting realized prices; the Company's ability to withstand commodity price volatility; risk management activities, including hedging and fixed price contracts; drilling plans including the timing of drilling; investments in pipeline and facility infrastructure; 2019 waterflood projects and the impact thereon on oil recoveries, corporate decline rates and production rates; the payout of wells and the timing thereof; expectations regarding timing of development of current inventory; oil and natural gas production levels, including annual average production and exit production in 2019 and the impact of oil curtailment thereon; decline rates; oil and liquids weighting and changes thereto; the 2019 drilling program, capital budget and guidance, including the Company's expectations to be self-sustaining in 2019; the weighting of activity levels between the first and second halves of 2019; Tamarack's intent to direct excess total adjusted operating field netback to debt repayment and continued funding share buy-backs for cancellation under the NCIB and RSU settlements; liquidity on existing credit facilities; shareholder returns; and enhanced per share metrics. 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 relating to: 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; and the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation.

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 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; and access to capital. 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 MD&A 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 and the Company's AIF for the year ended December 31, 2018 which will be filed on SEDAR by close of business February 27, 2019.

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, production, net asset value, net debt, debt-adjusted production per share, estimated year end 2019 net debt to Q4 annualized adjusted operating field netback ratio 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 made as of the date of this document and was provided for the purpose of providing further information about Tamarack's future business operations. 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 financial measures referred to in this press release, such as net debt, debt-adjusted production per share, adjusted operating field netbacks and net debt to annualized adjusted operating field netback ratio, are not prescribed by IFRS. Tamarack uses these measures to help evaluate its financial and operating performance as well as its liquidity and leverage. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

"Net debt" is calculated as long-term debt plus working capital surplus or deficit adjusted for risk management contracts.

"Debt adjusted production per share" is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt-adjusted share count is calculated as total shares outstanding plus incremental shares issued at a current market price to eliminate the change in net debt or in the case where debt decreases the reduction in shares. Management of Tamarack believes that debt adjusted production per share is useful in determining the production growth on a per share basis as if changes to debt was extinguished by the issuance or redemption of shares. The presentation of production growth on a per share basis is skewed for oil and gas companies that have more debt on their balance sheet and in their capital structure. Such companies will show better results because more of their growth is financed through debt than equity (as opposed to generating growth through realizing a rate of return on capital employed). The debt adjusted production per share measure provides a means of putting oil and gas companies on an equal, enterprise-based footing with respect to debt when calculating per share numbers. This measure is relevant to investors to appreciate the impact the debt on a company's balance sheet has on per share growth disclosure and the strength of one company's balance sheet relative to an over-leveraged peer, particularly in volatile commodity price environments where a company's indebtedness may increase as a result of lower cash flows and higher debt financing costs.

"Adjusted operating field netback" is calculated by taking net income or loss before taxes and adding back items, including transaction costs, and certain non-cash items including stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; impairment; unrealized gain or loss on financial instruments; and gain or loss on dispositions.

"Net debt to annualized adjusted operating field netback ratio" is calculated as net debt divided by annualized adjusted operating field netback for the most recent quarter.

"Operating Field Netback" is calculated as total petroleum and natural gas sales, less royalties and net production and transportation costs.

"Operating Netback" is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties and net production and transportation costs.

Please refer to the MD&A for additional information relating to Non-IFRS measures. The MD&A can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedar.com.

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