TSX: TVE

Tamarack Valley Energy Ltd. Announces a 43% Increase in Proved Developed Producing Reserves and an Operational Update

Calgary, Alberta – February 27, 2017 – Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is pleased to announce the results of its independent oil and gas reserves evaluation as of December 31, 2016, prepared by GLJ Petroleum Consultants Ltd. ("GLJ"), summarized below. The reserves evaluation contained herein does not include the impact of the Spur Resources Ltd. acquisition that closed January 11, 2017 (the "Viking Acquisition"). Pro-forma reserves details including the new assets from the Viking Acquisition will be made available concurrent with the Company's year-end 2016 financial and operating results with further details included in the 2016 Annual Information Form, both of which are expected to be issued and filed on March 23, 2017.

Throughout 2016, Tamarack continued to focus on the successful execution of its core strategy and strategic acquisitions generating positive results despite ongoing weakness in commodity prices. The Company achieved strong reserves additions organically due to the success of its drilling program, enhancements to completion techniques and improvements in well performance, all of which contributed to attractive capital efficiencies. Tamarack's complementary acquisitions during 2016 at Wilson Creek / Redwater and the low-decline acquired production at Penny (collectively the "Acquired Assets") further supported the growth profile and contributed to near and longer-term value creation. A successful development program and cost reductions on the Acquired Assets during the latter half of 2016 led to an increase in the net present value of before tax future net revenues discounted at 10% ("NPVBT10") of proved plus probable ("2P") reserves to approximately $240 million compared to the purchase price paid of $85 million in June of 2016.

The NPVBT10 of Tamarack's total 2P reserves increased by 61% year over year to $668.8 million, representing $4.55 per fully diluted share. Tamarack delivered 5% growth per fully diluted share in proved developed producing reserves ("PDP"), and increased its drilling location inventory while maintaining a strong balance sheet. On an absolute basis, the Company's significant reserves growth includes a 43% increase in PDP, a 34% increase in total proved ("1P") reserves and a 26% increase in 2P reserves.

2016 RESERVES REPORT HIGHLIGHTS

- PDP reserves increased by 43% on an absolute basis and by 5% per fully diluted share.
- Increased 1P reserves by 34% to 33.4 million boe, and 2P reserves by 26% to 56.5 million boe.
- Oil and natural gas liquids ("NGLs") weighting across all reserves categories increased to approximately 60% compared to 2015 weightings of approximately 50% on PDP, 52% on 1P and 54% on 2P.
- Significant increases in oil reserves of 85%, 67% and 45% on PDP, 1P and 2P, respectively, over 2015.
- As a percentage of total 2P reserves, 1P reserves increased from 56% to 59%.
- Including acquisitions, the Company replaced 322% of production on a 1P basis and 406% on a 2P basis.

- Maintained a consistent approach to reserves booking, with 1P reserves including only 67 (52.6 net) proved undeveloped horizontal Cardium drilling locations and 2P reserves including only 103 (81.1 net) proved plus probable undeveloped horizontal Cardium drilling locations.
- Achieved 1P finding and development (“F&D”) costs of approximately $14.44/boe and 1P finding, development and acquisition (“FD&A”) costs of approximately $14.68/boe, both including the change in future development capital ("FDC").
- Achieved 2P F&D costs of approximately $7.20/boe and 2P FD&A costs of approximately $11.34/boe, both including the change in FDC.
- Realized three year average 2P F&D costs of approximately $15.14/boe and 2P FD&A costs of $15.68/boe, both including the change in FDC.
- Generated a 2P F&D recycle ratio of 2.3 times and a 2P FD&A recycle ratio of 1.5 times using the estimated 2016 operating netback, excluding hedges, of $16.55/boe (unaudited) and a 2P F&D recycle ratio of 3.1 times and a 2P FD&A recycle ratio of 1.9 times using the estimated Q4 2016 operating netback, excluding hedges, of $22.03/boe (unaudited).
- Increased 2P reserve life index to 15.0 years based on estimated 2016 average production of 10,344 boe/d.

Reserves Snapshot by Category:

	PDP	**1P**	**2P**
Reserves Added(1) (mboe)	9,940	12,163	15,332
Total Reserves (mboe)(2)	20,517	33,404	56,544
Reserves Replacement	263%	322%	406%
NPV10 BT ($mm)	$281.1	$411.1	$668.8
FD&A Cost per boe(3)	$13.98	$14.68	$11.34
Recycle Ratio(4)	1.2x	1.1x	1.5x
F&D Cost per boe (3)	$23.72	$14.44	$7.20
Recycle Ratio(4)	-	1.1x	2.3x
Reserves per Fully Diluted Share Growth(4)	5%	(2%)	(8%)

(1) This number takes the difference in reserves year over year plus the production for the year.
(2) Total reserves are Company Interest reserves which include royalty volumes.
(3) Including changes in FDC.
(4) Based on a 2016 estimated operating netback excluding hedges of $16.55 per boe (unaudited).
(5) 2016 over 2015, based on 147.03 million shares outstanding and 107.61 million at December 31, 2016 and 2015, respectively.

2016 YEAR-END RESERVES SUMMARY & OPERATIONS UPDATE

The following tables highlight Tamarack’s 2016 year-end independent reserves assessment and evaluation prepared by GLJ with an effective date of December 31, 2016 (the “GLJ Report”). The GLJ Report 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 Canadian Oil and Gas Evaluation Handbook. All evaluations and summaries of future net revenue are stated prior to provision for interest, debt service charges or general 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.

Reserves Data (Forecast Prices and Costs) – Company Interest

RESERVES CATEGORY	CRUDE OIL[1] Gross (Mbbls)	CRUDE OIL[1] Net (Mbbls)	CONVENTIONAL NATURAL GAS Gross (Mmcf)	CONVENTIONAL NATURAL GAS Net (Mmcf)	NATURAL GAS LIQUIDS Gross (Mbbls)	NATURAL GAS LIQUIDS Net (Mbbls)	TOTAL OIL EQUIVALENT Gross (Mboe)	TOTAL OIL EQUIVALENT Net (Mboe)
PROVED:								
Developed Producing	10,157	8,718	49,995	44,047	2,027	1,559	20,517	17,619
Developed Non-Producing	101	92	1,505	1,276	6	4	358	308
Undeveloped	7,109	6,222	26,238	24,278	1,048	942	12,529	11,211
TOTAL PROVED	**17,368**	**15,032**	**77,738**	**69,602**	**3,081**	**2,506**	**33,404**	**29,138**
PROBABLE	11,030	9,452	56,870	50,794	2,631	2,228	23,139	20,146
TOTAL PROVED PLUS PROBABLE	**28,398**	**24,484**	**134,607**	**120,395**	**5,711**	**4,733**	**56,544**	**49,284**

Note:
(1) Heavy oil included in the Crude Oil product type represents less than 4% of any reserves category and as such is immaterial.
(2) Columns may not add due to rounding.

Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/yr)

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	489,515	346,063	281,091	241,478	213,792	15.95
Developed Non-Producing	3,286	2,101	1,626	1,370	1,195	5.27
Undeveloped	215,590	173,037	128,409	94,724	70,250	11.45
TOTAL PROVED	**708,391**	**521,202**	**411,127**	**337,572**	**285,237**	**14.11**
PROBABLE	621,559	382,273	257,658	185,274	139,703	12.79
TOTAL PROVED PLUS PROBABLE	**1,329,950**	**903,475**	**668,784**	**522,846**	**424,939**	**13.57**

Note:
(1) Unit values based on Company net 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

FACTORS	MBOE Proved	MBOE Probable	MBOE Proved + Probable
December 31, 2015	24,992	19,960	44,953
Discoveries	-	-	-
Extensions and Improved Recovery[1]	2,968	273	3,242
Technical Revisions	(331)	(1,670)	(2,001)
Acquisitions	10,373	4,911	15,284
Dispositions	(583)	(189)	(772)
Economic Factors	(276)	(156)	(432)
Production	(3,775)	-	(3,775)
December 31, 2016	**33,369**	**23,129**	**56,498**

Note:
(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
2017	37,267	43,709
2018	62,714	71,612
2019	65,620	101,258
2020 and Subsequent	69,145	184,238
Total Undiscounted FDC	234,747	400,818
Total Discounted FDC at 10% per year	189,534	309,658

Notes:
(1) FDC as per GLJ independent reserve evaluation effective December 31, 2016 based on GLJ forecast pricing.

FD&A Costs

	2016		Three Year Average	
(amounts in $000s except as noted)	Proved	Proved + Probable	Proved	Proved + Probable
FD&A costs, including FDC[(1)(2)]				
Exploration and development capital expenditures [(3)(4)]	56,546	56,546	87,209	87,209
Acquisitions, net of dispositions	82,386	86,386	91,213	91,213
Total change in FDC	39,656	34,944	47,655	65,861
Total FD&A capital, including change in FDC	**178,588**	**173,876**	**226,077**	**244,283**
Reserve additions, including revisions – Mboe	2,356	799	3,675	3,907
Acquisitions, net of dispositions – Mboe	9,807	14,533	7,096	11,677
Total FD&A Reserves	**12,163**	**15,332**	**10,770**	**15,583**
F&D costs, including FDC - $/boe	14.44	7.20	21.32	15.14
Acquisition costs, net of dispositions - $/boe	14.74	11.57	20.82	15.85
FD&A costs, including FDC - $/boe	**14.68**	**11.34**	**20.99**	**15.68**

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) Columns may not add due to rounding.

Operational Update

To date in the first quarter of 2017, Tamarack has remained focused on executing its capital program and continues to be on target for expected activity levels and production volumes. Since the start of the year, the Company has brought a total of 15 (13.9 net) new wells on production, including 11 (10.9 net) Viking light oil wells, two net extended reach horizontal Cardium light oil wells, one net Notikewin liquids-rich natural gas well, and one net heavy oil well. Volumes from these new wells are contributing to the Company's current production of approximately 19,000 boe/d and Tamarack remains on target to meet its first half production guidance range of 18,500 to 19,000 boe/d despite numerous factors negatively impacting field operations thus far in the first quarter. Tamarack has experienced non-operated production curtailments, a third-party gas plant curtailment, earlier than expected road bans due to warm weather and delays due to lack of availability of frack crews required for well completions. The Company has been able to continue to meet production and capital deployment expectations even while faced with multiple headwinds, demonstrating the high-quality nature of Tamarack's diverse asset base and its ability to efficiently operate and allocate capital and resources.

Based on three rigs currently running and Tamarack's capital plans for the balance of the first quarter, the Company anticipates bringing on an additional 15 (12.4 net) Viking wells and four (3.3 net) Cardium wells by the end of March, 2017 contributing to an estimated first quarter 2017 exit production rate of approximately 20,000 boe/d. Into the second quarter, nine (8.9 net) Viking wells and one net Cardium well that were drilled in the first quarter are expected to be brought on production, bolstering the Company's positive momentum through the first half of 2017.

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 – targeting repeatable and relatively predictable plays that provide long-life reserves, and 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 in the Cardium and Viking fairways primarily in Alberta that are economic at a variety 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 return 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
MMcf	million cubic feet
Mbbls	thousand barrels
mcf/d	thousand cubic feet per day

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel of oil equivalent ("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 Regulators' NI 51–101. Boe may be misleading, particularly if used in isolation.

Unaudited Financial Information

Certain financial and operating information included in this press release for the quarter and year ended December 31, 2016, including finding development and acquisition costs and netbacks are based on estimated unaudited financial results for the quarter and year then ended, and are subject to the same limitations as discussed under Forward Looking Information set out below. These estimated amounts may change upon the completion of audited financial statements for the year ended December 31, 2016 and changes could be material.

Information Regarding Disclosure on Oil and Gas Reserves

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "reserves replacement", “recycle ratio” and "reserve life index". These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon.

F&D cost calculations have been conducted in compliance with the requirements of NI 51-101. Specifically, F&D costs relating to Proved reserves were calculated by adding the cost of exploration, the cost of development and the annual change in estimated future reserves development costs and dividing that sum by annual additions to Proved reserves. Finding and development costs for Proved plus Probable reserves were similarly calculated, but used the Proved plus Probable reserves figure rather than the Proved reserves figure. The aggregate of the estimated 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. Tamarack also calculates FD&A costs using the same method, but without eliminating the effects of acquisitions and dispositions. Funds flow from operations netback are calculated in compliance with the requirements of NI 51-101 by subtracting royalties, operating costs, general and administrative costs, realized gains or losses on financial instruments and interest from revenue.

Recycle ratio is defined as operating netback per boe divided by F&D costs on a per boe basis. Reserves replacement ratio is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production. Reserve life index is calculated as Company gross reserves divided by average fourth quarter production annualized.

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 “plan”, “intend”, “ongoing”, “future”, “guidance”, “position”, “focus”, “monitor”, “target”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “could” or similar words suggesting future outcomes. More particularly, this press release contains statements concerning Tamarack’s planned future drilling plans; first half of 2017 production range; first quarter 2017 exit production; and timing to bring wells on production.

In addition, statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described 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 relating to prevailing commodity prices, the availability of drilling rigs 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, 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. Although management considers these assumptions to be reasonable based on information currently available to it, 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 (e.g. operational risks in development, exploration and production; 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 Tamarack's annual information form (AIF) for additional risk factors relating to Tamarack. The AIF is available for viewing 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.

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