MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the years ended December 31, 2016 and 2015. This MD&A is dated and based on information available on March 22, 2017 and should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2016 and 2015. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to section entitled "Non-IFRS Measures" on page 16. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

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 the Canadian Securities Regulators' National Instrument 51–101 Standards of Disclosure for Oil and Gas Activities. Boe may be misleading, particularly if used in isolation.

Abbreviations

Crude Oil		Natural Gas	
bbl	barrel	AECO	natural gas storage facility located at Suffield, AB
bbl/d	barrels per day	GJ	gigajoule
WTI	West Texas Intermediate	mcf	thousand cubic feet
		mcf/d	thousand cubic feet per day

Other	
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids

About Tamarack

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 primarily in the Cardium and Viking fairways 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.

Strategic Acquisitions Completed During the Year Ended December 31, 2016

During the year ended December 31, 2016, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny and Redwater Acquisitions") on July 12, 2016 and July 25, 2016, respectively. The assets in Penny are comprised of a light oil pool under waterflood with low recoveries and low decline rates plus strategic infrastructure, while the Redwater and Wilson Creek assets included 95 (60 net) sections of land and significant strategic infrastructure. The combined total purchase price for the Penny and Redwater Acquisitions was approximately $86 million, and as of the closing dates included approximately 1,900 boe/d of predominantly light oil and natural gas liquids production. The Company closed a bought deal financing on July 12, 2016 raising gross proceeds of $81.6 million which provided the primary funding for the Penny and Redwater Acquisitions.

Transformative Business Combination Adds Additional Viking Oil Assets

On January 11, 2017, Tamarack closed the previously announced arrangement agreement (the "Arrangement Agreement") providing for the acquisition by Tamarack of all of the issued and outstanding common shares of Spur Resources Ltd., which held Spur's Viking oil assets at closing (the "Viking Acquisition"). Under the terms of the Arrangement Agreement, the Company issued an aggregate of 90.1 million common shares of Tamarack and paid $57.3 million in cash. Tamarack also assumed Spur's net debt, estimated to be $25.7 million as at January 11, 2017, after accounting for proceeds from the exercise of all outstanding options of Spur, as well as severance and transaction costs. Based upon Tamarack's share price on January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $393 million. After giving effect to the Viking Acquisition at December 31, 2016, the Company estimates that its net debt would have been approximately $128 million.

As a result of the Viking Acquisition, Tamarack is repositioned as an intermediate oil-weighted Cardium and Viking-focused growth company with production of approximately 18,000 boe/d (56% light oil and NGLs) and over 800 net total identified drilling locations that pay out in 1.5 years or less at current strip prices. The Company expects to maintain financial strength and flexibility with pro forma net debt to 2017E cash flow at current strip prices of less than 1.0 times, and no immediate requirement for equity to fund development of the combined assets in 2017.

Production

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Production						
Light oil (bbls/d)	**4,858**	4,258	14	**4,215**	3,703	14
Heavy oil (bbls/d)	**316**	620	(49)	**363**	602	(40)
Natural gas liquids (bbls/d)	**1,075**	1,218	(12)	**1,035**	803	29
Natural gas (mcf/d)	**31,226**	23,229	34	**28,388**	20,038	42
Total (boe/d)	**11,453**	9,968	15	**10,344**	8,448	22
Percentage of oil and natural gas liquids	**55%**	61%		**54%**	60%	

Tamarack achieved strong production results for the year ended December 31, 2016, averaging 10,344 boe/d. Better than expected capital efficiencies and higher than expected production results from a successful 2016 drilling program and from the Penny and Redwater Acquisition contributed to volumes that exceeded annual average production guidance of 9,700 to 10,000 boe/d, despite experiencing over 400 boe/d of unexpected production curtailments in the second quarter of 2016 due to TransCanada pipeline curtailments.

Annual volumes in 2016 were 22% higher than the 8,448 boe/d produced during the same period in 2015, reflecting the impact of a full year of production from certain working interests acquired in the producing Alder Flats area of Alberta in mid-2015 (the "Wilson Creek / Alder Flats Acquisition") as well as the impact of nearly two full quarters of production from assets acquired in the Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Average production for the fourth quarter of 2016 increased by 6% to 11,453 boe/d from 10,790 boe/d in the third quarter of 2016, and was 15% higher than 9,968 boe/d in the fourth quarter of 2015. Fourth quarter volumes were positively impacted by a combined average of 878 boe/d attributable to a full quarter of production from the Penny and Redwater Acquisitions, and volume additions from one (1.0 net) Cardium oil wells and one (1.0 net) oil well in the Penny area that were brought on stream during the fourth quarter, partially offset by expected declines from existing production.

Crude oil and natural gas liquids production in the fourth quarter of 2016 averaged 6,249 bbls/d, an increase of 5% compared to the third quarter of 2016 production of 5,955 bbls/d. A combined average of 597 bbls/d were added due to a full quarter of production from the Penny and Redwater Acquisitions, and volume additions from one (1.0 net) Cardium oil well and one (1.0 net) oil well in the Penny area that were brought on stream during the fourth quarter.

Tamarack's oil and natural gas liquids represented 55% of total production in both the third and fourth quarters of 2016. For 2017, the Company expects its oil and natural gas liquids weighting to fluctuate between 55% and 62% depending on the timing of production additions from its higher oil-weighted areas of Wilson Creek, Redwater, Penny and assets from the Viking Acquisition, compared to additions coming from the higher natural gas-weighted area of Alder Flats. Oil and natural gas weightings may also be affected by production additions associated with future drilling of liquids-rich Mannville gas wells in the Wilson Creek area.

Natural gas production averaged 31,226 mcf/d in the fourth quarter of 2016, an increase of 8% over the 29,007 mcf/d produced in the prior quarter. The increase was primarily due to a reduction of TCPL curtailments and to a full quarter of production from the Penny and Redwater Acquisitions, which added a combined 1,686 mcf/d to the period’s production average.

Petroleum, Natural Gas Sales and Royalties

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Revenue						
Oil and NGLs	**$30,403,954**	$22,041,711	38	**$90,517,702**	$85,308,952	6
Natural gas	**9,389,261**	5,683,517	65	**24,999,247**	20,836,771	20
Total	**$39,793,215**	$27,725,228	44	**$115,516,949**	$106,145,723	9
Average realized prices:						
Light oil ($/bbl)	**58.71**	47.16	24	**50.53**	52.06	(3)
Heavy oil ($/bbl)	**44.60**	26.79	66	**35.45**	41.98	(16)
Natural gas liquids ($/bbl)	**28.99**	18.22	59	**20.74**	19.49	6
Combined average oil and NGLs ($/boe)	**52.88**	39.30	35	**44.06**	45.76	(4)
Natural gas ($/mcf)	**3.27**	2.66	23	**2.41**	2.85	(15)
Revenue $/boe	**37.76**	30.23	25	**30.51**	34.43	(11)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**60.76**	51.98	17	**51.76**	56.91	(9)
Hardisty Heavy (Cdn$/bbl)	**45.76**	37.04	24	**38.22**	45.54	(16)
AECO daily index (Cdn$/mcf)	**3.08**	2.47	25	**2.15**	2.69	(20)
AECO monthly index (Cdn$/mcf)	**2.80**	2.64	6	**2.08**	2.75	(24)
Royalty expenses	**$3,745,935**	$2,564,759	46	**$8,795,132**	$10,565,532	(17)
$/boe	**3.56**	2.80	27	**2.32**	3.43	(32)
percent of sales	**9**	9	–	**8**	10	(20)

Revenue from crude oil, natural gas and associated natural gas liquids sales was $39,793,215 in the fourth quarter of 2016, which was 26% higher than the $31,588,087 generated in the third quarter of 2016 and 44% higher than the $27,725,228 generated in the fourth quarter of 2015. The 26% increase in fourth quarter 2016 revenue over the previous quarter is attributable to natural gas prices that were 29% higher, crude oil and natural gas liquids prices that were 17% higher, a 5% increase in crude oil and natural gas liquids production and an 8% increase in natural gas production.

Revenue in the fourth quarter of 2016 increased 44% relative to the same period in 2015 primarily due to a 15% increase in production volumes, crude oil and natural gas liquids prices that were 35% higher and 23% higher natural gas prices.

Revenue during the year ended December 31, 2016 increased 9% to $115,516,949 compared to $106,145,723 in the same period in 2015 despite a 4% decrease in crude oil and natural gas liquids pricing and a 15% decrease in natural gas prices. The net increase was due to a 22% increase in production volumes.

Tamarack's realized prices for natural gas and the combined oil and natural gas liquids averaged $3.27/mcf and $52.88/bbl in the fourth quarter of 2016, respectively, compared to $2.54/mcf and $45.29/bbl in the third quarter of 2016 and $2.66/mcf and $39.30/bbl in the fourth quarter of 2015.

The realized crude oil prices for the three months and years ended December 31, 2016 and 2015 generally correlate to the posted Edmonton Par price for those periods. Natural gas liquids are priced at varying discounts to the posted Edmonton Par price depending on market conditions, pipeline capacity and seasonality. The pentane plus and butane components within natural gas liquids price, increased in the fourth quarter and year ended December 31, 2016 by a greater margin than the Edmonton Par price due to improved supply and demand conditions in North America. Propane prices also improved in the fourth quarter of 2016 due to inventory levels in North America returning to more normal levels supported by better supply and demand conditions.. The Company expects that natural gas liquids prices in 2017 will generally correlate to the posted Edmonton Par price..

The Company's realized heavy oil price for the fourth quarter of 2016 increased by a greater margin than the Hardisty Heavy price due to tightening differentials, while realized heavy oil prices for the years ended December 31, 2016 and 2015 generally correlate to the Hardisty Heavy price for the same periods.

For the three months and years ended December 31, 2016, Tamarack's realized natural gas prices generally correlate to AECO daily index pricing, however variances can arise during periods of rapid price increases or decreases, because the portion of the Company's sales that are based mainly on the daily index will not correlate to the monthly index.

At December 31, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,200 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $60.54
Crude oil	2,200 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.60
Crude oil	1,200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $65.05
Crude oil	1,200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.13
Natural gas	16,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.77
Natural gas	18,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.51
Natural gas	18,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.54
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79

At December 31, 2016, the commodity contracts were fair valued with a liability of $10,703,767 (December 31, 2015 – fair valued as an asset of $12,468,101) recorded on the balance sheet and an unrealized loss of $23,171,868 recorded in the net loss for the year ended December 31, 2016.

At December 31, 2016, the Company held physical commodity contracts as follows.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

Since December 31, 2016, the Company has entered into or assumed through the Viking Acquisition the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	800 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $70.21
Crude oil	800 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $70.14
Crude oil	1,100 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $72.05
Crude oil	400 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	US $55.23
Crude oil	800 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $71.88
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50
Crude oil	600 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $55.07
Natural gas	5,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $3.35
Natural gas	5,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $3.04
Natural gas	2,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.14

Royalty expenses for the fourth quarter of 2016 were $3.56/boe or $3,745,935, representing 9% of revenue, compared to $2.24/boe or $2,219,838 for the third quarter of 2016, representing 7% of revenue. The $1.32/boe increase in royalties in the fourth quarter of 2016 compared to the third quarter of 2016 was related to the sliding scale mechanism which results in higher royalties when commodity prices are higher.

Royalties as a percentage of revenue were similar in the fourth quarter of 2016 compared to the fourth quarter of 2015, when royalty expenses were $2.80/boe or $2,564,759, representing 9% of revenue.

The royalty expense for the year ended December 31, 2016 was $2.32/boe or $8,795,132, representing 8% of revenue, compared to $3.43/boe or $10,565,532, representing 10% of revenue for the same period in 2015. The decrease in royalties as a percentage of revenue for the year ended December 31, 2016 relative to 2015 is due to the sliding scale mechanism which results in lower royalties when commodity prices decline, lower initial royalty rates on wells that were drilled between late 2015 and during 2016, and the Company's annual gas cost allowance adjustment. These positive impacts were partially offset by higher royalty rates from wells acquired in the Wilson Creek / Alder Flats Acquisition in June 2015 and the Penny and Redwater Acquisitions in July 2016.

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF took effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. All wells drilled after January 1, 2017 will pay a 5% flat royalty until revenues exceed a normalized well cost allowance, which will be based on vertical well depth, lateral length (for horizontal wells) and total proppant used in the fracking of the well, after which royalty rates will range between 5% and 40% depending on commodity prices. The MRF is not expected to materially impact netbacks on Tamarack's existing assets nor is it expected to materially impact the economics of future drilling.

Production Expenses

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Total production expenses	**$12,826,236**	$11,182,990	15	**$44,067,395**	$39,496,609	12
Total ($/boe)	**$12.17**	$12.20	(0)	**$11.64**	$12.81	(9)

Production expenses for the fourth quarter of 2016 increased by 5% to $12.17/boe compared to $11.58/boe incurred during the third quarter of 2016. The operating costs on a per boe basis increased as a result of the Penny Acquisition which feature higher per unit operating costs than Tamarack realizes in its other areas. On an absolute basis, overall costs increased in the fourth quarter of 2016 to $12,826,236 compared to $11,493,859 in the third quarter of 2016. The increase in total production costs resulted from a 6% increase in production and the increase in per unit costs.

On a per unit basis, fourth quarter 2016 production expenses were similar to the $12.20/boe realized in the same quarter of 2015, but increased 15% on an absolute basis to $12,826,236, compared to $11,182,990 for the same period in 2015, matching the increase in production volumes during the same period.

Production expenses for the year ended December 31, 2016 were 9% lower at $11.64/boe compared to $12.81/boe during the same period in 2015, but increased 12% on an absolute basis to $44,067,395, compared to $39,496,609 for the same period in 2015. The lower per boe production expenses in 2016 resulted from cost reductions at the Wilson Creek / Alder Flats and Heavy oil properties and from the impact of higher volumes across fixed costs resulting in lower per unit costs. These cost reductions were partially offset by the Penny and Redwater Acquisitions which feature higher per unit operating costs than Tamarack realizes in its other areas. On an absolute basis, overall costs increased as a result of a 22% increase in production volumes partially offset by lower per unit costs.

It is anticipated that production expenses per boe in 2017 will remain in the $11.75 to $12.25 per boe range. Lower per unit operating costs on the assets acquired in the Viking Acquisition are expected to be offset by cost increases associated with the recently legislated carbon tax in Alberta.

Operating Netback

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Average realized sales	**37.76**	30.23	25	**30.51**	34.43	(11)
Royalty expenses	**(3.56)**	(2.80)	27	**(2.32)**	(3.43)	(32)
Production expenses	**(12.17)**	(12.20)	(0)	**(11.64)**	(12.81)	(9)
Operating field netback	**22.03**	15.23	45	**16.55**	18.19	(9)
Realized commodity hedging gain (loss)	**(0.15)**	8.16	(102)	**3.25**	5.67	(43)
Operating netback	**21.88**	23.39	(6)	**19.80**	23.86	(17)

Operating netback for the fourth quarter of 2016 increased by 9% to $21.88/boe compared to $20.10/boe during the third quarter of 2016. This is attributable to a 17% increase in oil and natural gas liquids prices ($52.88/bbl versus $45.29/bbl) and a 29% increase in natural gas prices ($3.27/mcf versus $2.54/mcf). These positive price impacts were partially offset by a 5% increase in operating expense per boe

($12.17/boe versus $11.58/boe), a realized hedging loss in the fourth quarter of 2016 compared to a hedging gain in the third quarter of 2016 (realized loss of $0.15/boe versus realized gain of $2.10/boe) and a 59% increase in royalty expense per boe ($3.56/boe versus $2.24/boe).

Relative to the same period the prior year, fourth quarter 2016 operating netbacks were 6% lower than the $23.39/boe generated in the fourth quarter of 2015. This was due to a fourth quarter 2016 realized hedging loss of $0.15/boe compared to a realized hedging gain of $8.16/boe in the same quarter of 2015 and royalty expenses per boe that were 27% higher ($3.56/boe versus $2.80/boe). Partially offsetting these impacts were price increases of 35% for oil and natural gas liquids in the fourth quarter of 2016 compared to 2015 ($52.88/bbl versus $39.30/bbl) and natural gas prices that were 23% higher ($3.27/mcf versus $2.66/mcf).

For the year ended December 31, 2016, operating netbacks decreased by 17% to $19.80/boe compared to $23.86/boe for the same period in 2015. The year over year change is attributable to a 4% decrease in oil and natural gas liquids prices ($44.06/bbl versus $45.76/bbl), a 15% decrease in natural gas prices ($2.41/mcf versus $2.85/mcf) and a smaller realized hedging gain of $3.25/boe during 2016 compared to $4.67/boe in 2015. Partially offsetting the pricing and hedging impacts were royalty expenses per boe that were 32% lower ($2.32/boe versus $3.43/boe) and operating expenses that were 9% lower ($11.64/boe versus $12.81/boe).

General and Administrative Expenses

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Gross costs	**$2,500,982**	$2,497,219	0	**$9,470,273**	$9,470,630	(0)
Capitalized costs and recoveries	**(511,369)**	(716,745)	(29)	**(2,075,366)**	(2,231,356)	(7)
General and administrative costs	**$1,989,613**	$1,780,474	12	**$7,394,907**	$7,239,274	2
Total ($/boe)	**$1.89**	$1.94	(3)	**$1.95**	$2.35	(17)

General and administrative ("G&A") expenses for the fourth quarter of 2016 were $1.89/boe on costs of $1,989,613 compared to $1.89/boe on costs of $1,872,202 in the third quarter of 2016. Fourth quarter 2016 G&A costs on an absolute basis were 6% higher than the previous quarter primarily due to the impact of a 6% increase in production and higher than expected year-end costs.

G&A costs per boe in the fourth quarter of 2016 were 2% lower than the $1.94/boe on costs of $1,780,474 in the same period of 2015, due to a 15% increase in production, partially offset by a 13% increase in absolute G&A costs.

For the year ended December 31, 2016, G&A expenses were $1.95/boe on costs of $7,394,907 compared to $2.35/boe on costs of $7,239,274 during the same period in 2015. On an absolute basis, G&A costs increased by only $155,633 during 2016 compared to 2015, but decreased by 17% on a per boe basis due primarily to a 22% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses relating to stock options and restricted share awards were $833,979 and $3,522,794, for the three months and year ended December 31, 2016, compared to $644,466 and $2,941,745 for the same periods in 2015. Stock-based compensation was higher in 2016 due to the increased number of granted options and restricted shares during the year. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $334,696 and $1,479,163 of stock-based compensation expenses relating to exploration and development activities for the three months and year ended December 31, 2016, compared to capitalizing $286,999 and $1,419,208 for the same periods in 2015.

For the three months and year ended December 31, 2016 the Company issued 945,000 options at a weighted average exercise price of $3.44 per share and issued 1,214,000 restricted stock units.

During the year ended December 31, 2016, 16,000 stock options at $2.06 per share were exercised for total gross proceeds of $32,960, 12,000 restrictive stock units were settled; and 270,833 stock options expired.

Interest

Interest expense was $615,602 and $3,392,096 for the three months and year ended December 31, 2016, respectively, compared to $1,065,904 and $5,109,876 for the same periods in 2015. The Company had $45,227,189 drawn on its revolving credit facility at December 31, 2016, compared to $82,821,860 drawn at December 31, 2015. Interest expense was lower for the three months and year ended December 31, 2016 compared to the same periods in 2015 due to a lower average amount drawn year-over-year on the revolving credit facility. The average amount drawn over the year in 2016 was approximately $56 million as compared to an average amount drawn of approximately $98 million in 2015.

Depletion, Depreciation, Amortization and Accretion

The Company depletes its property, plant, and equipment based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation assets is also amortized over its term to expiry, which is charged to depletion, depreciation, and amortization expense ("DDA&A").

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Depletion and depreciation	**$17,688,198**	$15,666,107	13	**$64,667,122**	$58,831,540	10
Amortization of undeveloped leases	**202,978**	147,644	37	**759,996**	715,644	6
Accretion	**526,583**	345,340	52	**1,695,817**	1,053,954	61
Total	**$18,417,759**	$16,159,091	14	**$67,122,935**	$60,601,138	11
Depletion and depreciation ($/boe)	**$16.79**	$17.08	(2)	**$17.08**	$19.08	(10)
Amortization ($/boe)	**0.19**	0.16	19	**0.20**	0.23	(13)
Accretion ($/boe)	**0.50**	0.38	32	**0.45**	0.34	32
Total ($/boe)	**$17.48**	$17.62	(1)	**$17.73**	$19.65	(10)

For the fourth quarter of 2016, DDA&A expense was $17.48/boe or $18,417,759 on an absolute basis, compared to $17.73/boe or $17,603,866 during the third quarter of 2016, due to a 6% increase in production, partially offset by lower DDA&A expense on a per boe basis. Relative to the same period in

2015, fourth quarter 2016 DDA&A expense of $17.48/boe was lower than the $17.62/boe for the fourth quarter of 2015. On an absolute basis, DDA&A expense of $18,417,759 was 18% higher in the fourth quarter of 2016 compared to $16,159,091 in the fourth quarter of 2015 due to a 15% increase in production, partially offset by lower DDA&A expense on a per boe basis.

For the year ended December 31, 2016 DDA&A expense was $17.73/boe, compared to $19.65/boe for the same period in 2015. The decrease per boe is attributable to increased production related to lower-cost Cardium and heavy oil properties, and impairments to property, plant and equipment taken in the third quarter of 2015. On an absolute basis, DDA&A expense was 12% higher in 2016 at $67,122,935, compared to $60,601,138 during the same period in 2015, caused by a 22% increase in production and partially offset by lower per unit DDA&A.

Income Taxes

The Company did not incur any cash tax expense in the three months and year ended December 31, 2016, nor does it expect to pay any cash taxes in 2017 or in 2018 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2016, a deferred income tax recovery of $403,311 and $4,800,136 were recognized, respectively, compared to a deferred income tax recovery of $345,943 and $8,411,305 for the same respective periods in 2015. There was a deferred tax recovery during the three months and years ended December 31, 2016 and 2015 due to a loss before taxes.

The following table outlines the Company's estimated tax pools as at December 31, 2016:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	33
Canadian development expense (CDE)	30%	134
Canadian oil and gas property expense (COGPE)	10%	226
Non-capital losses (NCL)	100%	181
Undepreciated capital cost (UCC)	25%	84
Share issue costs and other	various	14
Total		672

Funds from Operations and Net Loss

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$39,793,215**	$27,725,228	44	**$115,516,949**	$106,145,723	9
Royalties	**(3,745,935)**	(2,564,759)	(46)	**(8,795,132)**	(10,565,532)	17
Realized gain (loss) on financial instruments	**(162,646)**	7,483,525	(102)	**12,296,313**	17,471,102	(30)
Production expenses	**(12,826,236)**	(11,182,990)	(15)	**(44,067,395)**	(39,496,609)	(12)
General and administration expenses	**(1,989,613)**	(1,780,474)	(12)	**(7,394,907)**	(7,239,274)	(2)
Transaction costs	**–**	–	–	**(596,254)**	(1,044,308)	43
Interest	**(615,602)**	(1,065,904)	42	**(3,392,096)**	(5,109,876)	34
Funds from operations	**$20,453,183**	$18,614,626	10	**$63,567,478**	$60,161,226	6

Funds from operations during the fourth quarter of 2016 were $20,453,183 ($0.15 per share basic and diluted) compared to $16,672,211 ($0.12 per share basic and diluted) in the third quarter of 2016. The increase in the absolute amount is primarily the result of a 29% increase in natural gas prices, a 17%

increase in crude oil and natural gas liquids pricing, transaction costs totaling $596,254 that were incurred during the third quarter of 2016 and a 6% increase in production. The increases were partially offset by a 59% increase in royalty expense, a 12% increase in production expenses, and a realized loss on financial instruments in the fourth quarter of 2016.

Funds from operations for the three months ended December 31, 2016 of $20,453,183 ($0.15 per share basic and diluted) were higher on an absolute basis than the same period in 2015 of $18,614,626 ($0.19 per share basic and diluted), primarily due to a 35% increase in crude oil and natural gas liquids pricing, a 23% increase in natural gas prices and a 15% increase in production. The increase was partially offset by a 46% increase in royalty expense, a 15% increase in production expenses and a realized hedging loss in the fourth quarter of 2016 compared to a realized hedging gain in the fourth quarter of 2015.

Funds from operations during the year ended December 31, 2016 were $63,567,478 ($0.52 per share basic and diluted), compared to $60,161,226 ($0.66 per share basic and diluted) for the same period in 2015. The increase in 2016 was primarily the result of a 22% increase in production, lower royalty expense and lower interest expense, partially offset by a 15% decrease in natural gas pricing, a 4% decrease in crude oil and natural gas liquids pricing, higher production expenses related to increased production and a lower realized hedging gain for 2016 compared to 2015.

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$37.76**	$30.23	25	**$30.51**	$34.43	(11)
Royalties	**(3.56)**	(2.80)	(27)	**(2.32)**	(3.43)	32
Realized gain (loss) on financial instruments	**(0.15)**	8.16	(102)	**3.25**	5.67	(43)
Production expenses	**(12.17)**	(12.20)	0	**(11.64)**	(12.81)	9
General and administration expenses	**(1.89)**	(1.94)	3	**(1.95)**	(2.35)	17
Transaction costs	**–**	–	–	**(0.16)**	(0.34)	53
Interest	**(0.58)**	(1.16)	50	**(0.90)**	(1.66)	46
Funds from operations	**$19.41**	$20.29	(4)	**$16.79**	$19.51	(14)

Funds from operations in the fourth quarter of 2016 increased 16% to $19.41/boe from $16.79/boe in the third quarter of 2016 attributable to a 29% increase in natural gas prices and a 17% increase in crude oil and natural gas liquids pricing. The increases were partially offset by a 59% increase in royalty expense per boe, a 5% increase in production expenses per boe and a realized hedging loss in the fourth quarter of 2016 compared to a realized hedging gain in the third quarter of 2016.

The Company had a net loss of $8,424,255 ($0.06 per share basic and diluted) during the three months ended December 31, 2016, compared to a net loss of $3,194,857 ($0.02 per share basic and diluted) for the third quarter of 2016. The Company recorded a higher net loss for the fourth quarter of 2016 compared to the third quarter of 2016 as a result of a higher unrealized loss on financial instruments taken in the fourth quarter of 2016, a loss on the disposition of property, plant and equipment and an impairment to exploration and evaluation assets taken in the fourth quarter of 2016, partially offset by higher revenue in the fourth quarter of 2016.

The Company had a net loss of $8,424,255 ($0.06 per share basic and diluted) during the three months ended December 31, 2016, compared to net income of $5,118,919 ($0.05 per share basic and diluted) for the same period in 2015. Despite higher revenue in the fourth quarter of 2016 compared to 2015, the

Company recorded a net loss in the period compared to net income recorded in the fourth quarter of 2015. Factors contributing to the net loss include a realized hedging loss compared to a realized hedging gain in the same quarter of 2015, higher DDA&A expense in the fourth quarter of 2016, a loss on the disposition of property, plant and equipment as well as an impairment to exploration and evaluation assets taken in the fourth quarter of 2016 compared to a recovery to property, plant and equipment taken in the fourth quarter of 2015.

Tamarack recorded a net loss of $27,822,948 ($0.23 per share basic and diluted) for the year ended December 31, 2016, compared to net loss of $17,328,368 ($0.19 per share basic and diluted) for the same period in 2015. This was due to an unrealized hedging loss in 2016 compared to a unrealized hedging gain in 2015, a lower realized hedging gain in 2016 compared to 2015, higher depletion, depreciation and amortization expense in 2016, higher operating expenses in 2016, a higher loss on the disposition of property, plant and equipment in 2016 and an impairment to exploration and evaluation assets in 2016, partially offset by higher revenue in 2016 and an impairment to property, plant and equipment taken in 2015.

Capital Expenditures (including exploration and evaluation expenditures)

The following table summarizes capital spending and property dispositions, excluding non–cash items:

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Land	**603,512**	$242,713	149	**2,092,324**	$655,429	219
Geological and geophysical	**27,481**	622,839	(96)	**464,338**	675,834	(31)
Drilling and completion	**12,243,027**	13,322,297	(8)	**46,353,198**	41,390,533	12
Equipment and facilities	**1,729,701**	4,304,486	(60)	**6,587,472**	18,363,749	(64)
Capitalized G&A	**181,719**	133,124	37	**889,043**	845,811	5
Office equipment	**77,296**	116,926	(34)	**432,596**	268,747	61
Total capital expenditures	**$14,862,736**	$18,742,385	(21)	**$56,818,971**	$62,200,103	(9)
Property acquisitions	**(247,981)**	2,075,124	(112)	**86,156,054**	57,479,032	50
Proceeds from disposal of property, plant and equipment	**(2,197,925)**	(10,000,000)	(78)	**(2,197,925)**	(12,247,937)	(82)
Total net capital expenditures	**$12,416,830**	$10,817,509	15	**$140,777,100**	$107,431,198	31

During the fourth quarter of 2016, the Company completed and equipped two (2.0 net) previously drilled Viking oil wells in Redwater; drilled, completed and equipped one (1.0 net) horizontal Cardium oil well in Wilson Creek and one (1.0 net) horizontal well in Penny; spudded four (4.0 net) horizontal Cardium oil wells in Wilson Creek; and drilled and abandoned four (4.0) strat-test heavy oil wells in Hatton.

During the fourth quarter of 2016, the Company disposed of its interest in non-core producing properties in Virginia Hills and Wilson Creek, comprised of approximately 16 boe/d (56% liquids) for $2,197,925.

For the year ended December 31, 2016, the Company completed the drilling, completion and equipping of two (1.7 net) Cardium oil wells spudded in 2015; drilled, completed and equipped ten (9.4 net) horizontal Cardium oil wells, two (2.0 net) Viking oil wells, one (1.0 net) oil well in Penny, one (0.8 net) Mannville gas well and two (2.0 net) heavy oil wells. In addition, Tamarack drilled and abandoned four (4.0 net) strat-test heavy oil wells and spudded four (4.0 net) horizontal Cardium oil wells in Wilson Creek. The Company also completed a debottlenecking infrastructure project in the Alder Flats area in order to optimize operations by increasing capacity and reducing operating costs.

2016 Drilling Summary

Excluding strat-test wells but including wells spudded by December 31, 2016		
	Gross	Net
Heavy Oil	2.0	2.0
Viking	2.0	2.0
Mannville	1.0	0.8
Cardium	15.0	14.4
	20.0	19.2

The Company's net undeveloped land was 245,047 acres at the end of 2016.

Impairment

There were no indicators for impairment or impairment reversals identified in 2016, relating to the Company's property, plant and equipment (2015 - $26,175,000 of impairment was recorded for the year ended December 31, 2015 on the Company's property, plant and equipment).

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period. For the year ended December 31, 2016, the Company recognized an impairment of $715,000 related to the drill and abandonment of four vertical stratigraphic test wells in the Hatton area.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $52,316,066 at December 31, 2016, compared to $97,940,880 at December 31, 2015. During the year ended December 31, 2016 the Company reduced net debt by $45,624,814 which improved financial flexibility. Tamarack's December 31, 2016 net debt to fourth quarter annualized funds from operations was 0.6 times, compared to 1.3 times at December 31, 2015.

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures ("CEE"), at $5.00 per share for total gross proceeds of $2,500,000. Under the terms of the flow-through share agreement, the Company is required to renounce the $2,500,000 of qualifying oil and natural gas expenditures effective December 31, 2016 and incur the expenditures by December 31, 2017. As of December 31, 2016 the Company has not incurred any of the qualifying oil and natural gas expenditures.

On July 12, 2016 the Company completed a bought deal financing in concert with the Penny and Redwater Acquisitions, resulting in the issuance of 20,110,050 common shares at $3.66 per share for total gross proceeds of $73,602,783. This included an over-allotment option being exercised for 2,623,050 common shares. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817.

On July 12, 2016 the Company also issued 1,952,000 flow-through common shares related to Canadian development expenditures at $4.10 per share for total gross proceeds of $8,003,200. Certain officers and directors acquired 4,900 flow-through common shares for gross proceeds of $20,090. As of December 31, 2016 the Company has incurred the full amount of the qualifying oil and natural gas expenditures.

On March 18, 2016, the Company completed a bought deal financing and issued 14,966,100 Common Shares at $2.92 per share for total gross proceeds of $43,701,012. This included the exercise of an over-allotment option for 1,952,100 Common Shares. Certain officers, directors and employees acquired

281,335 common shares for gross proceeds of $821,498.

During the year ended December 31, 2016, 16,000 stock options at $2.06 per share were exercised for total gross proceeds of $32,960. There were also 12,000 restricted share awards converted to common shares.

At December 31, 2016 there were 137,527,475 common shares, 5,327,051 options and 3,063,167 restricted share awards outstanding. At March 22, 2017 there were 227,670,381 common shares, 5,377,051 options and 3,196,667 restricted share awards outstanding. This compares to December 31, 2015 at which time there were 99,971,325 common shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. The Company had 137,043,779 and 122,235,231 weighted average basic common shares outstanding during the three months and year ended December 31, 2016. No preferred shares of the Company are issued and outstanding.

At December 31, 2016, the Company had a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility totals $120 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018.

The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 1.0% to a high of the bank’s prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the credit facilities. The Facility has been secured by a $300 million supplemental debenture with a floating charge over all assets. As the available lending limits of the two facilities are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled to take place on May 26, 2017.

Pursuant to the terms of the Facility, the Company has provided a covenant that at all times its adjusted working capital ratio shall not be less than 1.0 to 1.0 which shall be calculated on a quarterly basis. The adjusted working capital ratio is defined under the terms of the Facility as current assets, excluding derivative assets and including the undrawn portion of the Facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities. The Company is in compliance with all of its covenants.

Subsequent to December 31, 2016 and the successful completion of the Viking Acquisition on January 11, 2017, the Company’s syndicate of lenders adjusted the revolving credit facility to $200 million with a $20 million operating facility (collectively the “Facility”). All other terms and conditions of the previous facility remained intact.

With the recent decrease in commodity prices and continued volatility in the oil and gas industry, Tamarack’s strategy remains focused on preserving balance sheet strength by adjusting capital spending relative to changes in commodity prices. The Company intends to maintain balance sheet flexibility to be able to fund its 2017 capital program while remaining opportunistic and positioned to take advantage of potential tuck-in acquisitions within its core areas while commodity prices remain low. The equity issuances in 2016, the Penny and Redwater Acquisitions and the Viking Acquisition are consistent with that strategy. In 2017, Tamarack will focus on drilling wells that target a payout of 1.5 years or less, positioning the Company to achieve production per share growth. The Company will also continue to focus on reducing capital costs and operating costs in order to optimize capital efficiencies.

The Company anticipates that funds from operations, together with current cash balances and the Facility,

will be sufficient to finance current operations, planned capital expenditures and any working capital requirements for the next twelve months and foreseeable future.

2017 Guidance

Tamarack's 2017 capital program and associated guidance is designed to meet the objective of maintaining a strong and flexible balance sheet in the context of a volatile commodity price environment while delivering per share growth in production and funds flow from operations. The Company's 2017 guidance:

- Annual average production between 19,000-20,000 boe/d (approximately 55-60% liquids), with 2017 exit production estimated between 20,000-21,000 boe/d (approximately 57-62% liquids);
- Planned capital expenditure range of $165 to $175 million, with first half 2017 expenditures $65 to $75 million;
- Estimated year end 2017 fourth quarter annualized debt to cash flow (including hedges) ratio below 0.9 times with an estimated $70-75 million of liquidity on the Company's existing credit facilities; and
- Using assumed 2017 commodity prices: WTI averaging $55/bbl USD, Edmonton Par price averaging $64.45/bbl, AECO averaging $2.65/GJ and a Canadian/US dollar exchange rate of $0.76.

The Company's top priority is to maintain a strong balance sheet in order to have the flexibility to exploit opportunities that may arise in this low commodity environment including the pursuit of tuck-in acquisitions within core areas and to continue adding high-quality drilling inventory. Tamarack will continue to closely monitor the broader commodity price environment and has the ability to accelerate or reduce capital expenditures in accordance with commodity price fluctuations from current levels.

Commitments

The following table summarizes the Company's commitments at December 31, 2016:

	2017	2018	2019	2020	2021	2022	2023
Office lease	641,312	541,718	541,718	262,535	–	–	–
Flow through shares	2,500,000	–	–	–	–	–	–
Take or pay commitments[(1)]	985,500	985,500	–	–	–	–	–
Rental fee[(2)]	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	9,296,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate in the Wilson Creek area is subject to a take-or-pay provision of $9.00/m3. The remaining term is 24 months.

(2) Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $119,000 per month for a maximum period of 90 months starting in January 2016 relating to four additional facilities.

Non–IFRS Measures

This document contains the terms “net debt” and “netbacks”, which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. 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. The Company uses net debt (bank debt net of working capital and excluding fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers corporate netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a boe basis by deducting royalties and operating costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts.

(a) **Operating Netback** - Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and operating costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates its field level profitability relative to current commodity prices. The calculation of the Company’s netbacks can be seen on page 7 in the section titled “Operating Netback.”

(b) **Net Debt -** Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Management considers net debt an important measure to assist in providing a more complete understanding of cash liabilities.

The following outlines the Company’s calculation of net debt (excluding the effect of derivative contracts):

	December 31, 2016	December 31, 2015
Bank debt	$45,227,189	$82,821,860
Accounts payable and accrued liabilities	25,015,088	31,730,161
Accounts receivable	(16,556,746)	(15,571,507)
Prepaid expenses and deposits	(1,369,465)	(1,039,634)
Net debt	$52,316,066	$97,940,880

Selected Quarterly Information

Three months ended	**Dec. 31, 2016**	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015
Sales volumes								
Natural gas *(mcf/d)*	**31,226**	29,007	27,462	25,818	23,229	22,005	16,972	17,864
Oil and NGL's *(bbls/d)*	**6,249**	5,955	4,959	5,279	6,096	5,049	4,163	5,115
Average boe/d *(6:1)*	**11,453**	10,790	9,536	9,582	9,968	8,717	6,992	8,092
Product prices								
Natural gas *($/mcf)*	**3.27**	2.54	1.62	2.03	2.66	3.04	2.80	2.91
Oil and NGL's *($/bbl)*	**52.88**	45.29	45.35	30.90	39.30	46.56	55.47	48.33
Oil equivalent *($/boe)*	**37.76**	31.82	28.25	22.50	30.23	34.64	39.82	34.75
(000s, except per share amounts)								
Financial results								
Gross revenues	**39,793**	31,588	24,517	19,619	27,725	27,779	25,331	25,311
Funds from operations	**20,453**	16,672	15,364	11,078	18,615	14,618	13,186	13,743
Per share – basic	**0.15**	0.12	0.13	0.11	0.19	0.15	0.16	0.18
Per share – diluted	**0.15**	0.12	0.13	0.11	0.18	0.15	0.16	0.18
Net income (loss)	**(8,424)**	(3,195)	(10,639)	(5,835)	5,119	(15,064)	(2,142)	(5,242)
Per share – basic	**(0.06)**	(0.02)	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)
Per share – diluted	**(0.06)**	(0.02)	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)
Additions to property and equipment, net of proceeds	**12,665**	14,497	10,310	17,149	8,743	21,936	14,246	5,028
Net property acquisitions	**(248)**	85,857	–	–	2,075	1,230	54,174	–
Total assets	**663,564**	679,259	542,917	553,135	549,068	549,652	561,977	482,227
Net debt[(1)]	**(52,316)**	(62,817)	(57,791)	(62,696)	(97,941)	(105,837)	(97,280)	(121,159)
Bank debt	**45,227**	48,598	48,630	50,056	82,822	94,423	88,500	112,951
Decommissioning obligations	**112,115**	122,810	68,149	65,643	63,331	61,808	64,883	45,340
Deferred income tax (asset)	**(41,714)**	(41,496)	(42,116)	(38,576)	(36,168)	(35,770)	(33,647)	(28,802)

(1) Excluding fair value of financial instruments

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and the resultant effect on revenue and net income (loss).
- The volatility in forward price curves which affects the mark-to-market calculation of derivative commodity contracts, and results in swings in earnings.
- The recorded impairment charges on the Company's oil and natural gas related Cash Generating Units ("CGUs") due to falling oil and gas prices in the amount of $29,100,000 in the third quarter of 2015.
- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions, comprised of certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $15,426,229 to oil and natural gas revenue and contributed $85,289 to the net loss.
- On June 15, 2015, the Company completed the Wilson Creek / Alder Flats Acquisition which added $7,266,186 to oil and natural gas revenue and contributed $1,045,845 to net loss in 2015.

- The Company recorded $596,254 in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions and $1,044,308 in transaction costs in the second and third quarters of 2015 related to the Wilson Creek / Alder Flats Acquisition.

Selected Annual Information

	2016	2015	2014
Sales volumes			
Natural gas *(mcf/d)*	**28,388**	20,038	13,292
Oil and NGL's *(bbls/d)*	**4,215**	3,703	3,245
Average boe/d *(6:1)*	**10,344**	8,448	5,717
Product prices			
Natural gas *($/mcf)*	**2.41**	2.85	4.28
Oil and NGL's *($/bbl)*	**50.53**	52.06	82.34
Oil equivalent *($/boe)*	**30.51**	34.43	60.38
(000s, except per share amounts)			
Financial Results			
Gross revenues	**115,517**	106,146	125,992
Net income (loss)	**(28,093)**	(17,329)	(25,166)
Per share – basic	**(0.23)**	(0.19)	(0.40)
Per share – diluted	**(0.23)**	(0.19)	(0.40)
Additions to property and equipment, net of proceeds	**140,230**	107,432	288,903
Total assets	**663,564**	549,068	497,578
Working capital (deficiency)[(1)]	**(52,316)**	(97,941)	(129,799)
Decommissioning obligations	**112,115**	63,331	41,357
Deferred income tax asset	**(41,714)**	(36,168)	(27,299)

(1) Excluding fair value of financial instruments

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and the effect this has had on revenue and net income (loss). The volatility in forward price curves also affects the mark-to-market calculation which results in swings in earnings.
- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions, comprised of certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $15,426,229 to oil and natural gas revenue and contributed $85,829 to the net loss.
- On June 15, 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta; in 2015 this acquisition added $7,266,186 to oil and natural gas revenue and contributed $1,045,845 to net loss.
- On September 30, 2014, the Company acquired 100% of a major's interests in the Wilson Creek area of Alberta; in 2014 this acquisition added $5,551,131 to oil and natural gas revenue and contributed $402,656 to net income.
- The Company recorded $596,254 in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions. The Company recorded $1,044,308 in transaction costs in

the second and third quarters of 2015 related the Alder Flats Acquisition and $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition.

- The Company recorded impairment charges on its heavy oil, light oil and certain natural gas related CGU's due to falling oil and gas prices in the amount of $26,175,000 in 2015 and $56,290,000 in 2014. There were no impairments or reversals recorded in 2016.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

(a) **Oil and natural gas reserves** – Oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, 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.

An independent reserve evaluator using all available geological and reservoir data, as well as historical production data, has prepared the Company's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans.

(b) **Exploration and evaluation assets –** The costs of drilling exploratory wells are initially capitalized as exploration and evaluation ("E&E") assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, estimated production costs and capital expenditures.

(c) **Depletion, depreciation, amortization and impairment –** Property, plant and equipment is measured at cost less accumulated depletion, depreciation, amortization, and impairment losses. The net carrying value of property, plant and equipment and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation assets or development and production assets within property, plant and equipment. Exploration and evaluation assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. The allocation of the Company's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for the Company's products and the way in which management monitors operations.

Exploration and evaluation expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a

mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, the Company performs an impairment test related to the specific CGU. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

(d) **Decommissioning obligations –** The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk free rate. The costs are included in property, plant and equipment and amortized over its useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

(e) **Share-based compensation –** The Company uses the fair value method for valuing stock option and preferred share grants. Under this method, compensation cost attributable to all share options and preferred shares granted is measured at fair value at the grant date and expensed over the vesting period. The Black-Scholes option pricing model is used to estimate the fair value of the stock options and preferred shares and it contains such estimates as expected share price volatility and the Company's risk-free interest rate. Any changes in these assumptions could alter the fair value and net earnings.

(f) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(g) **Financial instruments** – The Company utilizes financial instruments to manage the exposure to market risks relating to commodity prices. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices and foreign currency exchange rates.

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures ("DCP") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures and have concluded that the Company's disclosure controls and procedures are effective.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting and concluded that the Company's internal controls over financial reporting are effective. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecast. Most of these risks (financial, operational or regulatory) are not within the Company's control. While the following sections discuss some of these risks, they should not be construed as exhaustive.

Financial Risks

Financial risks include commodity pricing; exchange and interest rates; and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company's control and can significantly affect the Company's financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while crude oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. As a result of both of these factors, Tamarack may enter into derivative instruments to partially mitigate the effects of downward price volatility. To evaluate the need for hedging, management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects, the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completions technology.

Insurance is in place to protect against major asset destruction or business interruption, including well blow-outs and pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the current cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack employees address the continued development of a new or established reservoir on a go-forward basis, using the same procedure that is used to address exploration risk. The decision to produce reserves is made based on the amount of capital required, production practices and reservoir quality. Tamarack evaluates reservoir development based on the timing, amount of additional capital required and the expected change in production values. Finding and development costs are controlled when capital is employed cost-effectively.

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. Restrictive new legislation is a risk the Company cannot control.

Forward Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable securities laws. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "can", "potential", "target", "intend", "focus", "identify", "manage", "could", "should", "believe" and similar expressions. The Company believes that the expectations reflected in such forward-looking statements are reasonable but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to:

- Pro forma net debt to 2017E cash flow.
- No immediate requirement for equity to fund development of the assets in 2017.

- Estimated production rates in 2017.
- The effect of the MRF on netbacks and economics of future drilling.
- The effect of the recently legislated carbon tax in Alberta.
- Future operating costs.
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing operating costs on newly acquired assets.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- Future capital expenditures and capital program funding.
- Estimated year end debt to cash flow (including hedges) ratio.
- The Company's capital program and guidance for 2017.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas pricing in 2017.
- Expectations as to oil and natural gas weighting in 2017.
- The ability of the Company to take advantage of opportunities that may arise while commodity prices are low.

With respect to the forward-looking statements contained in this MD&A, Tamarack has made assumptions regarding, among other things:

- future commodity prices;
- expected operating costs;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions or the Viking Acquisition or the acquisition of undeveloped lands Tamarack considers prospective for hydrocarbons;
- drilling results including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax and regulatory regime.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2016, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

The forward-looking statements contained in this MD&A are made as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Drilling Locations

In this MD&A, the 800 net drilling locations identified include 283 proved locations, 507 proved and probable locations and 293 un-booked locations. Proved locations and probable locations account for drilling locations that have associated proved and/or probable reserves, as applicable. Un-booked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Un-booked locations do not have attributed reserves or resources. While certain of the un-booked drilling locations have been de-risked by drilling existing wells in relative close proximity to such un-booked drilling locations, the majority of un-booked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

tamarack valley ENERGY ltd.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in this report are the responsibility of management. Management, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Tamarack Valley Energy Ltd. (the "Company"). The consolidated financial statements have been prepared within acceptable limits of materiality and when necessary, management has made estimates using their best judgment.

Management is responsible for the integrity of the financial information. Management has established internal control systems designed to provide reasonable assurance that transactions are properly authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable accounting information for financial reporting purposes.

The Company's Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Company's Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with Management and their external auditors to discuss internal controls over financial reporting process, audit results and financial reporting matters to satisfy itself that each party is discharging its responsibilities, and to review the consolidated financial statements and the external auditors' report. The external auditors have access to the Audit Committee on a quarterly basis without the presence of management. The Board of Directors has approved the consolidated financial statements.

(signed)
Brian Schmidt
President & Chief Executive Officer

(signed)
Ron Hozjan
Vice-President & Chief Financial Officer

Calgary, Alberta
March 23, 2017

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tamarack Valley Energy Ltd.

We have audited the accompanying consolidated financial statements of Tamarack Valley Energy Ltd., which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Tamarack Valley Energy Ltd. as at December 31, 2016 and December 31, 2015, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants March 22, 2017

Calgary, Canada

TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets

	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Accounts receivable	$16,556,746	$15,571,507
Prepaid expenses and deposits	1,369,465	1,039,634
Fair value of financial instruments (note 5)	–	12,468,101
	17,926,211	29,079,242
Property, plant and equipment (note 7)	601,419,568	481,615,900
Exploration and evaluation assets (note 9)	2,503,772	2,204,978
Deferred tax asset (note 14)	41,714,274	36,167,594
	$663,563,825	$549,067,714
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$25,015,088	$31,730,161
Fair value of financial instruments (note 5)	10,703,767	–
	35,718,855	31,730,161
Bank debt (note 17)	45,227,189	82,821,860
Decommissioning obligations (note 10)	112,114,594	63,330,850
Deferred flow-through share premium	765,000	–
Shareholders' equity:		
Share capital (note 15)	537,553,964	416,075,358
Contributed surplus	21,942,090	17,044,404
Deficit	(89,757,867)	(61,934,919)
	469,738,187	371,184,843
Commitments and contingencies (note 19)		
Subsequent event (note 20)		
	$663,563,825	$549,067,714

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

(signed)
Floyd Price
Director

(signed)
Dean Setoguchi
Director

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Loss and Comprehensive Loss
For the years ended December 31, 2016 and 2015

	2016	2015
Revenue:		
Oil and natural gas	$115,516,949	$106,145,723
Royalties	(8,795,132)	(10,565,532)
Realized gain on financial instruments (note 5)	12,296,313	17,471,102
Unrealized (loss) gain on financial instruments (note 5)	(23,171,868)	3,997,191
	95,846,262	117,048,484
Expenses:		
Production	44,067,395	39,496,609
General and administration	7,394,907	7,239,274
Transaction costs (note 6)	596,254	1,044,308
Stock-based compensation (note 18)	3,522,794	2,941,745
Finance (note 12)	5,087,913	6,163,830
Depletion, depreciation and amortization	65,427,118	59,547,184
Loss on disposition of property, plant and equipment (note 7)	1,472,608	180,207
Impairment of property, plant and equipment (note 8)	–	26,175,000
Impairment of exploration and evaluation assets (note 9)	715,000	–
	128,283,989	142,788,157
Loss before taxes	(32,437,727)	(25,739,673)
Deferred income tax recovery (note 14)	4,614,779	8,411,305
Net loss and comprehensive loss	$(27,822,948)	$(17,328,368)
Net loss per share (note 16):		
Basic	$(0.23)	$(0.19)
Diluted	$(0.23)	$(0.19)

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Changes in Equity

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2015	77,928,466	$336,086,662	$12,931,358	$(44,606,551)	$304,411,469
Issue of common shares	19,818,459	74,860,360	–	–	74,860,360
Issue of flow-through shares	2,224,400	9,208,700	–	–	9,208,700
Share issue costs, net of tax of $1,292,148	–	(3,493,586)	–	–	(3,493,586)
Transfer on exercise of stock options and preferred shares	–	247,906	(247,906)	–	–
Flow-through share premium	–	(834,684)	–	–	(834,684)
Stock-based compensation	–	–	4,360,952	–	4,360,952
Net loss	–	–	–	(17,328,368)	(17,328,368)
Balance at December 31, 2015	99,971,325	$416,075,358	$17,044,404	$(61,934,919)	$371,184,843
Issue of common shares	35,104,150	117,336,755	–	–	117,336,755
Issue of flow-through shares	2,452,000	10,503,200	–	–	10,503,200
Share issue costs, net of tax of $1,790,781	–	(4,841,740)	–	–	(4,841,740)
Transfer on exercise of stock options and preferred shares	–	104,271	(104,271)	–	–
Flow-through share premium	–	(1,623,880)	–	–	(1,623,880)
Stock-based compensation	–	–	5,001,957	–	5,001,957
Net loss	–	–	–	(27,822,948)	(27,822,948)
Balance at December 31, 2016	137,527,475	$537,553,964	$21,942,090	$(89,757,867)	$469,738,187

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2016 and 2015

	2016	2015
Cash provided by (used in):		
Operating:		
Net loss	$(27,822,948)	$(17,328,368)
Items not involving cash:		
Depletion, depreciation and amortization	65,427,118	59,547,184
Stock-based compensation	3,522,794	2,941,745
Loss on disposition of property, plant and equipment	1,472,608	180,207
Accretion expense on decommissioning obligations	1,695,817	1,053,954
Unrealized gain (loss) on financial instruments	23,171,868	(3,997,191)
Impairment of property, plant and equipment	–	26,175,000
Impairment of exploration and evaluation assets	715,000	–
Deferred income tax recovery	(4,614,779)	(8,411,305)
Funds from operations	63,567,478	60,161,226
Abandonment expenditures (note 10)	(217,940)	(155,559)
Changes in non-cash working capital (note 13)	(2,611,825)	1,383,273
Cash provided by operating activities	60,737,713	61,388,940
Financing:		
Change in bank debt	(37,594,671)	(17,378,140)
Proceeds from issuance of shares	127,839,955	84,069,060
Share issue costs	(6,632,521)	(4,785,734)
Cash provided by financing activities	83,612,763	61,905,186
Investing:		
Property, plant and equipment additions	(53,833,518)	(61,759,267)
Exploration and evaluation additions	(2,985,453)	(440,838)
Acquisitions	(85,060,174)	(58,288,466)
Proceeds from disposal of property, plant and equipment	2,197,925	12,247,937
Changes in non-cash working capital (note 13)	(4,669,256)	(15,883,596)
Cash used in investing activities	(144,350,476)	(124,124,230)
Change in cash and cash equivalents	–	(830,104)
Cash and cash equivalents, beginning of year	–	830,104
Cash and cash equivalents, end of year	$ –	$ –

See accompanying notes to the consolidated financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is incorporated under the Business Corporations Act (Alberta). The consolidated financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd and has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. The Company is engaged in the exploration for, development and production of, oil and natural gas.

Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. The address of its head office is Suite 600, 425 – 1st Street S.W., Calgary, Alberta T2P 3L8.

2. Basis of preparation:

(a) Statement of compliance:

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The consolidated financial statements were authorized for issue by the Board of Directors on March 22, 2017.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments which are measured at fair value.

(c) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars, which is the Company's and its subsidiaries functional currency, other than Tamarack Ridge Resources Inc. that has a United States dollar functional currency.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

i) Critical judgments in applying accounting policies

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

The Company's assets are aggregated into cash-generating units for the purpose of calculating impairment. Cash generating units ("CGU" or "CGUs") are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

ii) Key sources of estimation uncertainty

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

Estimation of recoverable quantities of proven and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows and the amount and timing of further development capital as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101.

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation

activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

The Company's estimate of stock-based compensation is dependent upon estimates of historic volatility and forfeiture rates.

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently by the Company and its subsidiaries to all years presented in these consolidated financial statements.

(a) Basis of consolidation:

i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in profit or loss.

ii) Jointly owned assets:

Many of the Company's oil and natural gas activities involve jointly owned assets. The consolidated financial statements include the Company's share of these jointly owned assets and a proportionate share of the relevant revenue and related costs. The relationship with jointly owned asset partners has been referred to as joint venture in

the remainder of the financial statements as is common in the Canadian oil and gas industry.

iii) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments:

i) Non–derivative financial instruments:

Non–derivative financial instruments may be comprised of cash and cash equivalents, accounts receivable, bank debt and accounts payable and accrued liabilities. Non–derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition, non–derivative financial instruments are measured as described below.

Cash and cash equivalents may include cash on hand, term deposits held with banks and other short–term highly liquid investments with original maturities of three months or less.

The Company's non–derivative financial instruments, such as cash and cash equivalents, accounts receivable, bank debt and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

ii) Derivative financial instruments:

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Company considers all commodities contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company has accounted for its forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the balance sheet. Settlements on these physical sales contracts are recognized in profit or loss.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in

the fair value of separable embedded derivatives are recognized immediately in profit or loss.

iii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant and equipment and exploration and evaluation assets:

i) Recognition and measurement:

Exploration and evaluation expenditures:

Pre–license costs are recognized in profit or loss as incurred.

Exploration and evaluation costs, including the costs of acquiring licenses, initially are capitalized as exploration and evaluation assets. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are evaluated at a CGU level.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered.

Upon determination of proven and/or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGU's for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal or the fair value of the asset received or given up with the carrying amount of the related property, plant and equipment given up and are recognized net in profit or loss.

ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day–to–day servicing of property, plant and equipment are recognized in profit or loss as incurred.

iii) Depletion, depreciation and amortization:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the energy equivalent ratio of six thousand cubic feet of natural gas to one barrel of crude oil. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Exploration and evaluation assets pertaining to land are amortized on a straight line basis over the term of the lease.

For other assets, depreciation is recognized in profit or loss on a percentage basis based on the useful life of the assets. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

The estimated depreciation rates for other assets for the current and comparative years are as follows:

Computer hardware and software	30 %
Office equipment, fixtures and fittings	20 %

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(d) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each

year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company's balance sheet. Payments made under operating leases are recognized in profit or loss on a straight–line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(e) Impairment:

i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

ii) Non–financial assets:

The carrying amounts of the Company's non–financial assets, other than E&E (exploration and evaluation) assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets, which are evaluated with the related cash generating unit when they are assessed for impairment, are assessed for impairment when they are reclassified to property, plant and equipment and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre–tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the other assets in the unit or group of units on a pro rata basis.

Any impairment losses in respect of property, plant and equipment and exploration and evaluation assets, recognized in prior years, are assessed at each reporting date for any indications that the losses have decreased or no longer exist. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(f) Share based payments:

The grant date fair value of preferred shares, stock options and restricted share units granted to employees is recognized as compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of awards that vest.

(g) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre–tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

ii) Onerous contracts:

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected

net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on associated assets.

(h) Revenue:

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(i) Finance income and expenses:

Finance expense comprises interest expense on bank debt, accretion of the discount on decommissioning obligations and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(j) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss, except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) Flow–through shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow–through share arrangements are renounced to investors in accordance with tax legislation. On issuance, the premium received on the flow–through shares, being the difference in price over a common share with no tax attributes, is recognized on the balance sheet. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized in profit or loss along with a pro–rata portion of the deferred premium.

(l) Earnings per share:

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as preferred shares, stock options and restricted share units granted to employees.

(m) Future standards and interpretations:

Leases - In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in the Consolidated Statements of Income (Loss) when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the dollar impact of adopting IFRS 16 on the Company’s consolidated financial statements.

Revenue from contracts with customers - In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Early adoption is permitted. The Company is currently in the scoping phase of implementation. Adopting IFRS 15 is not expected to have a material impact on the Company's consolidated financial statements.

Financial Instruments - In July 2014, the IASB issued IFRS 9, “Financial Instruments” to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value

resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward looking 'expected loss' impairment model that will result in more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted. The adoption of IFRS 9 is not expected to have a material impact on the Company's consolidated financial statements.

Amendments to IAS 7 Statement of Cash Flows - In April 2016, the IASB issued amendments to IAS 7 "*Statement of Cash Flows"* for annual periods beginning on or after January 1, 2017, with earlier application permitted. The amendments require entities to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The Company is currently evaluating the impact of the amendments on the financial statement.

Amendments to IFRS 2 Share-based Payment - In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment transactions. The adoption of the amendments is not expected to have a material impact on the Company's consolidated financial statements.

4. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(a) Property, plant and equipment and exploration and evaluation assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of other items of property, plant and equipment and exploration and evaluation assets is based on the quoted market prices for similar items.

(b) Cash and cash equivalents, accounts receivable, bank debt and accounts payable and accrued liabilities:

The fair value of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2016 and 2015, the fair value of these balances approximated their carrying value due to their short term to maturity.

Bank debt bears a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value.

(c) Stock options, preferred shares and restricted share units:

The fair value of employee stock options and preferred shares is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on weighted average historic volatility, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividend yield and the weighted average risk-free interest rate based on government bonds. Restricted share units are valued at the share price on the measurement date.

(d) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at future value to profit and loss and therefore carrying amount equals future value.

5. Financial risk management:

(a) Overview:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Company's activities.

(b) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers and favorable mark-to-market positions on financial instruments. The maximum exposure to credit risk at year-end is as follows:

	Carrying amount	
	2016	2015
Accounts receivable	**$16,556,746**	$15,571,507
Fair value of financial instruments	–	12,468,101
Total	**$16,556,746**	$28,039,608

Accounts receivable:

All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from crude oil and natural gas purchasers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its crude oil and natural gas purchasers.

Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining joint venture partner pre-approval of significant capital expenditures.

However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners; as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners; however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment.

Derivative assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to derivative assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such a provision for doubtful accounts has not been recorded at December 31, 2016 and 2015.

The maximum exposure to credit risk for accounts receivable at the reporting date by type of customer was:

	Carrying amount	
	2016	2015
Oil and natural gas marketing companies	**$ 14,079,178**	$9,509,233
Joint venture partners	**1,218,550**	5,619,150
Other	**1,259,018**	443,124
Total accounts receivable	**$16,556,746**	$15,571,507

The Company's seven most significant customers, five Canadian oil and natural gas marketer's, and two joint venture partners, account for $14,278,593 of the trade receivables at December 31, 2016 (2015: four Canadian oil and natural gas marketer's, three joint venture partner accounted

for $13,636,033). The Company received payment for $15,674,700 by the end of February, 2017. The Company has the ability to offset approximately 90% of the remaining outstanding amounts against current accounts payable from the same joint venture partners.

As at December 31, 2016 and 2015, the Company's accounts receivable are aged as follows:

	2016	2015
Current (less than 90 days)	**$15,906,788**	$12,110,732
Past due (more than 90 days)	**649,958**	3,460,775
Total accounts receivable	**$16,556,746**	$15,571,507

(c) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically, the Company ensures that it has sufficient cash or banking line available to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditure. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Company maintains a $120.0 million revolving credit facility to provide capital when needed, of which $74.8 million was available at the end of the year.

The timing of cash flows relating to financial liabilities as at December 31, 2016 is as follows:

	Total	1 Year	2 to 3 years	Beyond 3 years
Account payable and accrued liabilities	$ 25,015,088	$ 25,015,088	–	–
Bank debt	45,227,189	–	45,227,189	–
Total financial liabilities	$70,242,277	$25,015,088	45,227,189	–

(d) Market risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Currency risk:

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally a decrease in the value of the $CDN as compared to the $US will increase the prices received by the Company for its petroleum and natural gas sales. The Company did not have any foreign exchange contracts as at December 31, 2016 and 2015.

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank loan fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2016, net loss would have been affected by $411,000 (2015 – net loss would have been affected by $716,000) based on the average debt balance outstanding during the year.

Commodity price risk:

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar, and also world economic events that dictate the levels of supply and demand.

At December 31, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	2,200 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $60.54	($2,588,745)
Crude oil	2,200 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.60	($2,830,483)
Crude oil	1,200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $65.05	($1,236,916)
Crude oil	1,200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.13	($671,190)
Natural gas	16,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.77	($855,927)
Natural gas	18,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.51	($1,030,040)
Natural gas	18,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.54	($1,001,688)
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79	($488,778)
					($10,703,767)

At December 31, 2016, the commodity contracts were fair valued with a liability of $10,703,767 (December 31, 2015 – fair valued as an asset of $12,468,101) recorded on the balance sheet and an unrealized loss of $23,171,868 recorded in loss for the year ended December 31, 2016.

Subject Contract	Effect of an increase in price on after-tax earnings	Effect of a decrease in price on after-tax earnings
Cdn $1.00 change in the oil price	$(602,941)	$602,941
Cdn $0.10 change in the gas price	$(463,490)	$463,490

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue. At December 31, 2016, the Company held physical commodity contracts as follows.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

Risk management contracts assets and liabilities are offset and the net amount presented in the balance sheet when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

The following table sets out gross amounts relating to risk management contracts assets and liabilities that have been presented on a net basis on the balance sheet.

Gross Amounts	**December 31, 2016**	December 31, 2015
Risk management contracts		
Current asset	**$ –**	$12,468,101
Current liability	**(10,703,767)**	–
Balance, end of the period	**$(10,703,767)**	$12,468,101

Since December 31, 2016, the Company has entered into or assumed through the acquisition of all of the issued and outstanding common shares of Spur Resources Ltd., which held Spur's Viking oil assets at closing (the "Viking Acquisition") on January 11, 2017, the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	800 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $70.21
Crude oil	800 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $70.14
Crude oil	1,100 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $72.05
Crude oil	400 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	US $55.23
Crude oil	800 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $71.88
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50
Crude oil	600 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $55.07
Natural gas	5,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $3.35
Natural gas	5,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $3.04
Natural gas	2,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.14

(e) Capital management:

The Company's policy is to maintain a strong capital base to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized funds from operations. This ratio is calculated as net debt, defined as outstanding bank debt plus accounts payable and accrued liabilities minus accounts receivable and prepaid expenses and deposits divided by funds from operations for the most recent calendar quarter and then annualized. The Company's strategy during a period of stable commodity prices is to maintain a ratio of not more than 1.5 times. This ratio may increase or decrease at certain times as a result of acquisitions, timing of employing capital versus bringing wells on production or significant upward/downward fluctuations in commodity prices.

With the recent decrease in commodity prices and increased volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by limiting capital spending to projected cash flow from operations, using strip prices. The Company's 2017 capital expenditure program was based on maintaining a debt to funds from operations ratio of less than 1.0 times.

The Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2016, the Company's ratio of net debt to annualized fourth quarter funds from operations was 0.6 to 1.

	2016	2015
Bank debt	**$45,227,189**	$82,821,860
Accounts payable and accrued liabilities	**25,015,088**	31,730,161
Accounts receivable	**(16,556,746)**	(15,571,507)
Prepaid expenses and deposits	**(1,369,465)**	(1,039,634)
Net debt	**52,316,066**	97,940,880
Fourth quarter funds from operations	**$20,453,183**	$18,614,626
Annualized factor	**4**	4
Annualized funds from operation	**81,812,732**	74,458,504
Debt to annualized funds from operation	**(0.6)**	(1.3)

There were no changes in the Company's approach to capital management during the year.

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves.

6. Property acquisitions:

(a) Penny and Redwater

On July 12, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Penny area of Southern Alberta ("Penny Acquisition") for an aggregate cash purchase price of approximately $58.8 million after closing adjustments.

On July 25, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Redwater and Wilson Creek areas of Alberta ("Redwater Acquisition") for an aggregate cash purchase price of approximately $27.3 million after closing adjustments.

The Penny Acquisition represents a new oil-weighted core area for the Company focused on the Barons formation, while the Redwater Acquisition complements the Company's existing Viking oil properties. The operations from the acquisitions have been included in the results of the Company commencing in July of 2016. The Company incurred transaction costs of $596,254, which were expensed through the statement of loss.

The allocation of the purchase price is as follows:

Consideration:	**Penny Acquisition**	**Redwater Acquisition**	**Total**
Cash	$ 58,826,536	$ 26,233,638	$ 85,060,174
Working capital settled	–	1,095,880	1,095,880
Total consideration	$ 58,826,536	27,329,518	$ 86,156,054
Net Assets Acquired:			
Prepaid expenses	$ 948,191	$ 896,751	$ 1,844,942
Property, plant and equipment	67,466,175	37,626,509	105,092,684
Decommissioning obligations	(9,587,830)	(11,193,742)	(20,781,572)
Net assets	$ 58,826,536	$ 27,329,518	$ 86,156,054

The fair value of property, plant and equipment has been determined with reference to a reserve report. The fair value of decommissioning obligations was initially estimated using a credit adjusted rate of 8%.

Included in the statement of loss are the following amounts for the Penny and Redwater Acquisitions since the date of acquisitions:

	Penny Acquisition	Redwater Acquisition	Total
Oil and natural gas revenue	$9,095,487	$6,330,742	$15,426,229
Net income (loss)	406,398	(492,227)	(85,289)

If the Penny and Redwater properties had been acquired on January 1, 2016, the incremental oil and natural gas revenue and income recognized for the period ended December 31, 2016 and the pro forma results would have been as follows:

Year ended December 31, 2016	As stated	Penny Acquisition prior to acquisition	Redwater Acquisition prior to acquisition	Pro Forma
Oil and natural gas revenue	$115,516,949	$9,603,285	$6,220,459	$131,340,693
Net loss	(27,822.978)	(671,954)	(4,596,797)	(33,091,729)

(b) Alder Flats

In June 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta for an aggregate cash purchase price of $54.8 million. The purpose of this acquisition was to increase the Company's exposure to the Cardium oil play. The operations from the acquisition have been included in the results of the Company commencing in June of 2015. The Company incurred transaction costs of $1,044,308, which were expensed through the statement of loss.

The allocation of the purchase price is as follows:

Cash Consideration:		
Total consideration	$	54,787,642
Net Assets Acquired:		
Prepaid expenses	$	809,434
Property, plant and equipment		61,446,538
Decommissioning obligations		(7,468,330)
Net assets	$	54,787,642

The fair value of property, plant and equipment has been determined with reference to a reserve report. The fair value of decommissioning obligations was initially estimated using a credit adjusted rate of 8%.

7. Property, plant and equipment:

	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2015	$585,493,847	$332,484	$585,826,331
Property acquisition	66,716,576	–	66,716,576
Cash additions	61,490,520	268,747	61,759,267
Decommissioning costs	12,207,496	–	12,207,496
Stock-based compensation	1,419,207	–	1,419,207
Transfer from exploration and evaluation assets	1,989,039	–	1,989,039
Disposals	(12,928,641)	–	(12,928,641)
Balance at December 31, 2015	716,388,044	601,231	716,989,275
Property acquisition	105,092,684	–	105,092,684
Cash additions	53,400,922	432,596	53,833,518
Decommissioning costs	28,621,577	–	28,621,577
Stock-based compensation	1,479,163	–	1,479,163
Transfer from exploration and evaluation assets	1,211,663	–	1,211,663
Disposals	(7,025,254)	–	(7,025,254)
Balance at December 31, 2016	$899,168,799	$1,033,827	$900,202,626
Depletion, depreciation and impairment losses:			
Balance at January 1, 2015	$150,320,639	$177,576	$150,498,215
Depletion and depreciation	58,744,439	87,101	58,831,540
Disposals	(131,380)	–	(131,380)
Impairment loss	26,175,000	–	26,175,000
Balance at December 31, 2015	235,108,698	264,677	235,373,375
Depletion and depreciation	64,494,315	172,807	64,667,122
Disposals	(1,257,439)	–	(1,257,439)
Balance at December 31, 2016	$298,345,574	$437,484	$298,783,058

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2015	$481,279,346	$336,554	$481,615,900
At December 31, 2016	$600,823,225	$596,343	$601,419,568

(a) Security:

At December 31, 2016 and 2015, all of the Company's properties are pledged as security for the bank debt.

(b) Contingencies:

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

(c) Dispositions:

For the year ended December 31, 2016 the Company disposed of three non-core, producing properties for $2,197,925. For the year ended December 31, 2015 the Company disposed of its interest in certain oil and pas infrastructure for $10,000,000 and two non-core, producing properties for $2,247,937 for total proceeds of $12,247,937. The Company has entered into operating leases regarding the oil and gas infrastructure, payments of which is included in commitments.

(d) Other:

The calculation of depletion at December 31, 2016 includes estimated future development costs of $400,816,000 (December 31, 2015 – $361,667,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $32,759,178 (December 31, 2015 – $25,630,409).

8. Impairment loss:

		2016	2015
Impairment losses:			
Property, plant and equipment	**$**	–	$26,175,000
	$	–	$26,175,000

(a) 2016 assessment:

There were no indications of impairment or impairment reversals for the year ended December 31, 2016 on the Company's property, plant and equipment.

(b) Results of 2015 assessment:

An impairment charge of $26,175,000 was recorded for the year ended December 31, 2015 on the Company's property, plant and equipment. The impairment charge is the result of a dramatic and sustained decrease in current and forecast forward commodity prices. The impairment recognized in 2015 specifically relates to the Quaich ($816,000), Hanlan ($712,000), Minor Properties ($561,000), Peace River Arch ($1,108,000) and Viking Oil ($25,769,000) CGU's with a minor impairment reversal of $2,791,000 due to enhanced reserve bookings on the Heavy Oil CGU. The recoverable value as at December 31, 2015 of these CGU's was Quaich: $3,934,000, Hanlan: nil, Minor Properties: nil, Peace River Arch: $1,700,000, Viking Oil: $43,417,000 and Heavy Oil: $9,580,000. The recoverable value of the Company's CGU's was estimated at the value in use based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company at varying discount rates of 8% to 15% depending on the particular reserve characteristics of the CGU. The prices used to estimate value in use are the average of those used by three independent industry reserve companies. As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods.

The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2015, as forecasted by the independent external reserves evaluator:

	2016	2017	2018	2019	2020	2021	2022	2023	Thereafter
WTI (US$/bbl)[1]	44.67	55.20	63.47	71.00	74.77	78.24	81.75	85.37	+1.8%/yr
Edmonton Par (Cdn$/bbl)[1]	55.89	66.47	73.21	81.35	84.57	87.88	92.01	96.24	+1.8%/yr
AECO (Cdn$/MMbtu)[1]	2.57	3.14	3.47	3.80	4.05	4.22	4.37	4.54	+1.8%/yr

(1) Price forecast, effective January 1, 2016.

9. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2015	$23,631,049
Additions	440,838
Transfer to property, plant and equipment	(1,989,039)
Balance at December 31, 2015	22,082,848
Additions	2,985,453
Transfer to property, plant and equipment	(1,211,663)
Balance at December 31, 2016	$23,856,638
Amortization and impairment:	
Balance at January 1, 2015	$19,162,226
Amortization	715,644
Balance at December 31, 2015	19,877,870
Amortization	759,996
Impairment loss	715,000
Balance at December 31, 2016	$ 21,352,866

	Total
Carrying amounts:	
At December 31, 2015	$2,204,978
At December 31, 2016	$2,503,772

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period. For the year ended December 31, 2016 the Company recognized an impairment of $715,000 related to the drill and abandonment of four vertical stratigraphic test wells in the Hatton area.

10. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total

undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately $114.3 million at December 31, 2016 (December 31, 2015 – $64.0 million), which is expected to be incurred between 2017 and 2038. A risk-free rate of 2.3% (2015 – 2.2%) and an inflation rate of 2% (2015 – 2%) is used to calculate the fair value of the decommissioning obligations at December 31, 2016 as presented in the table below:

	December 31, 2016	December 31, 2015
Balance, beginning of the year	**$63,330,850**	$41,356,532
Liabilities incurred	**1,546,461**	1,091,390
Liabilities acquired	**20,781,572**	9,237,544
Change in estimates	**(5,970,039)**	444,130
Change in discount rate on acquisition	**33,045,155**	10,671,976
Expenditures	**(217,940)**	(155,559)
Liabilities disposed	**(2,097,282)**	(369,117)
Accretion	**1,695,817**	1,053,954
Balance, end of the year	**$112,114,594**	$63,330,850

The decommissioning obligations acquired in the Penny and Redwater Acquisitions during 2016 and the Alder Flats acquisition during 2015, were initially recognized using a fair value discount rate of 8%. They were subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

A change in estimate for 2016 resulted from the decommissioning obligations being revalued using the risk-free rate of 2.3% as opposed to the risk free rate of 2.2% used in 2015. A change in estimate for 2015 resulted from the decommissioning obligations being revalued using the risk-free rate of 2.2% as opposed to the risk free rate of 2.5% used in 2014.

11. Personnel expenses:

The aggregate payroll expense of employees and executive management was as follows:

	2016	2015
Wages and salaries	**$5,460,354**	$5,183,806
Benefits and other personnel costs	**663,569**	287,705
Stock-based compensation	**4,487,609**	3,575,237
Total employee remuneration	**10,611,532**	9,046,748
Capitalized portion of total remuneration	**(3,554,529)**	(3,650,564)
	$7,057,003	$5,396,184

Personnel expenses directly attributed to capital activities have been capitalized and included in property, plant and equipment and intangible exploration and evaluation assets.

In addition to their salaries, the Company also provides non-cash benefits to executive officers and employees. The executive officers include the President and Chief Executive Officer, the VP Finance and Chief Financial Officer, the VP Engineering, the VP Land, the VP Exploration and the VP Production and Operations. Executive officers, employees and directors may also participate in the Company's option and restricted share unit program. Key executive officers' compensation is comprised of the following:

	2016	2015
Salaries, wages and short term benefits	**$2,441,202**	$2,736,251
Share-based payments [(1)]	**2,431,663**	1,879,403
	$4,872,865	$4,615,654

(1) Represents the amortization of stock-based compensation associated with restricted share units, options and preferred shares granted to executive officers as recorded in the financial statements.

12. Finance expenses:

	2016	2015
Interest on bank loans	**$3,392,096**	$5,109,876
Accretion of decommissioning obligations	**1,695,817**	1,053,954
	$5,087,913	$6,163,830

13. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	2016	2015
Source/(use of cash):		
Accounts receivable	**$(985,239)**	$4,799,169
Prepaid expenses and deposits	**$(329,831)**	(228,651)
Accounts payable and accrued liabilities	**(6,715,073)**	(19,880,275)
Working capital on acquisition (note 6)	**749,062**	809,434
	$(7,281,081)	$(14,500,323)
Related to operating activities	**$(2,611,825)**	$1,383,273
Related to investing activities	**$(4,669,256)**	$(15,883,596)

14. Income tax expense:

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to the loss before taxes as follows:

	2016	2015
Loss before taxes	**($32,437,727)**	($25,739,673)
Expected tax rate	**27.00%**	26.02%
Expected income tax reduction	**(8,758,186)**	(6,698,184)
Flow-through shares	**1,301,984**	1,651,665
Change in unrecognized deferred tax assets	**976,755**	301,389
Stock-based compensation	**951,154**	765,524
Change in rates and other	**913,514**	(4,431,699)
Total	**(4,614,779)**	(8,411,305)

In 2016, the blended statutory tax rate was 27.00% (2015 – 26.02%). The increase from 2015 was due to an increase in the Alberta provincial rate from 10% to 12% effective July 1, 2015.

Deferred tax assets and liabilities are attributable to the following:

	2016	2015
Deferred tax liabilities:		
Property, plant and equipment	**$(44,527,884)**	$(24,615,676)
Financial instruments	**–**	(3,366,388)
Deferred tax assets:		
Financial instruments	**2,890,016**	
Non-capital losses	**49,400,907**	43,686,165
Share issue costs	**3,680,295**	3,364,164
Decommissioning obligations	**30,270,940**	17,099,329
Total	**$41,714,274**	$36,167,594

In calculating the deferred income tax asset in 2016, the Company included $186 million (2015 - $165 million) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2026 and 2036.

The Company has recognized a net deferred tax asset based on an independent evaluated reserve report as cash flows are expected to be sufficient to realize the deferred tax asset.

Deferred tax assets have not been recognized in respect of the following item:

	2016	2015
Property, plant and equipment	**$18,687,104**	$15,069,494

A continuity of the net deferred tax asset (liability) is detailed in the following tables:

	Balance January 1, 2015	Recognized In equity	Recognized in profit or loss	Other	Balance December 31, 2015
Property, plant and equipment	$(9,947,512)	$ –	$(9,764,718)	($834,684)	$(20,546,914)
Non-capital losses	29,755,985	–	13,930,180	–	43,686,165
Decommissioning obligations	10,355,500	–	6,743,829	–	17,099,329
Share issue costs	3,023,306	1,292,148	(951,290)	–	3,364,164
Unrecognized deferred tax assets	(3,767,373)	–	(301,389)	–	(4,068,762)
Financial instruments	(2,121,081)	–	(1,245,307)	–	(3,366,388)
Total	$27,298,825	$1,292,148	$8,411,305	($834,684)	$36,167,594

	Balance January 1, 2016	Recognized In equity	Recognized in profit or loss	Other	Balance December 31, 2016
Property, plant and equipment	$(20,546,915)	$ –	$(18,076,573)	($858,880)	$(39,482,368)
Non-capital losses	43,686,165	–	5,714,742	–	49,400,907
Decommissioning obligations	17,099,329	–	13,171,611	–	30,270,940
Share issue costs	3,364,164	1,790,781	(1,474,650)	–	3,680,295
Unrecognized deferred tax assets	(4,068,761)	–	(976,755)	–	(5,045,516)
Financial instruments	(3,366,388)	–	6,256,404	–	2,890,016
Total	$36,167,594	$1,790,781	$4,614,779	($858,880)	$41,714,274

15. Share capital:

At December 31, 2016 and 2015 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

2016:

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2,500,000. Under the terms of the flow-through share agreements, the Company is required to renounce the $2,500,000 of qualifying oil and natural gas expenditures effective December 31, 2016 and must incur the

expenditures by December 31, 2017. As of December 31, 2016, the Company has not incurred any of the qualifying oil and natural gas expenditures.

On July 12, 2016, the Company completed a bought deal financing by issuing 20,110,050 common shares at $3.66 per share for total gross proceeds of $73,602,783. This included an over-allotment option that was exercised for 2,623,050 common shares. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817.

On July 12, 2016, the Company also issued 1,952,000 flow-through common shares, related to Canadian development expenditures, at $4.10 per share for total gross proceeds of $8,003,200. Certain officers, directors and employees acquired 4,900 flow-through common shares for gross proceeds of $20,090. The Company renounced these expenditures on December 31, 2016 and had fully incurred the required expenditures.

On March 18, 2016, the Company completed a bought deal financing by issuing 14,966,100 common shares at $2.92 per share for total gross proceeds of $43,701,012. This included an over-allotment option that was exercised for 1,952,100 common shares. Certain officers, directors and employees acquired 281,335 common shares for gross proceeds of $821,498.

During the year ended December 31, 2016 16,000 stock options at $2.06 per share were exercised for gross proceeds of $32,960. There were also 12,000 restricted share awards converted to common shares.

2015:

On December 3, 2015, the Company issued 37,600 flow-through common shares, related to Canadian exploration expenditures, at $3.55 per share for total gross proceeds of $133,480. Certain officers, directors and employees acquired 28,400 flow-through common shares for gross proceeds of $100,820. The Company renounced these expenditures on December 31, 2015 and had fully incurred the required expenditures.

On June 3, 2015, the Company completed a bought deal financing by issuing 17,197,000 common shares at $3.78 per share for total gross proceeds of $65,004,660. Certain officers, directors and employees acquired 18,600 common shares for gross proceeds of $70,308. On June 10, 2015, the over-allotment option was exercised resulting in the issuance of 2,579,550 common shares.

On June 3, 2015, the Company also issued 2,186,800 flow-through common shares, related to Canadian development expenditures, at $4.15 per share for total gross proceeds of $9,075,220. Certain officers, directors and employees acquired 26,800 flow-through common shares for gross proceeds of $111,220. The Company renounced these expenditures on December 31, 2015 and had fully incurred the required expenditures.

During the year ended December 31, 2015, 65,416 preferred shares were exchanged into 12,742 common shares on cashless basis and 29,167 stock options at $3.60 per share were exercised for total gross proceeds of $105,001.

16. Income (loss) per share:

The following table summarizes the net loss and weighted average shares used in calculating the net loss per share:

	Years ended December 31,	
	2016	2015
Net loss	**$(27,822,948)**	$(17,328,368)
Weighted average shares - basic	**122,235,231**	90,661,207
Weighted average shares - diluted	**122,235,231**	90,661,207
Net loss per share-basic	**$(0.23)**	$(0.19)
Net loss per share-diluted	**$(0.23)**	$(0.19)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the year ended December 31, 2016, 9,500,802 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive. For the year ended December 31, 2015, 7,640,635 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive.

17. Bank debt:

The Company has available a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility, totaling $120 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018.

The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 1.0%, to a high of the bank’s prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the credit facilities. The Facility has been secured by a $300 million supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled to take place on May 26, 2017.

Pursuant to the terms of the Facility, the Company has provided a covenant that at all times its adjusted working capital ratio shall not be less than 1.0 to 1.0. The adjusted working capital ratio is defined under the terms of the credit facilities as current assets excluding derivative assets, including the undrawn portion of the Facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities.

Subsequent to December 31, 2016 and the successful completion of the Viking Acquisition on January 11, 2017, the Company’s revolving credit facility was adjusted to $200 million with a $20 million operating facility (collectively the “Facility”) with a syndicate of lenders.

At December 31, 2016, the Company had utilized the Facility in the amount of $45.2 million and the Company was compliant with its working capital ratio at 3.7 to 1.0.

As at December 31, 2016, the Company had letter of guarantees outstanding in the amount of $73,980 against the Facility.

18. Share-based payments:

(a) Preferred share plan:

Under the Company's preferred share plan, preferred shares of Tamarack Acquisition Corp. are exchangeable into common shares of the Company upon payment of $3.12 per common share. The preferred shares of Tamarack Acquisition Corp. are fully vested at December 31, 2016 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share. An exchange of the preferred shares is at the election of the Company under certain circumstances.

As at December 31, 2016 there are 1,110,584 (December 31, 2015 – 1,110,584) common shares underlying preferred shares outstanding and exercisable with an exchange price of $3.12 per common share.

Under the terms of the Company's preferred share plan, a cashless settlement alternative is available, whereby preferred share-holders can either (i) elect to receive shares by delivering cash to the Company in the amount of the preferred shares, or (ii) elect to receive a number of shares equivalent to the market value of the preferred share over the exercise price. For the year ended December 31, 2016 there were no preferred shares exercised. During the year ended December 31, 2015 preferred share-holders exercised 65,416 preferred shares on a cashless settlement basis and received 12,742 common shares.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 13,752,748 options or restricted share units to its employees, directors and consultants of which 8,982,948 options, preferred shares and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 945,000 options granted during the year ended December 31, 2016 (2015 – 727,000).

The fair value of each option granted during the year was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2016	2015
Risk free rate (%)	**0.92**	0.90
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**2.14**	1.79

The number and weighted average exercise prices of stock option plan are as follows:

	Number of options	Weighted average exercise price
Outstanding, January 1, 2015	4,147,386	$ 3.70
Granted	727,000	2.84
Exercised	(29,167)	3.60
Forfeited	(134,668)	2.94
Expired	(41,667)	4.44
Outstanding, December 31, 2015	4,668,884	$ 3.59
Granted	945,000	3.44
Exercised	(16,000)	2.06
Expired	(270,833)	4.55
Outstanding, December 31, 2016	**5,327,051**	**$ 3.52**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2016:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price
$ 1.86 – 3.00	1,737,051	$2.35	1.9	1,323,719	$2.23
$ 3.01 – 5.00	3,124,000	$3.67	2.9	1,907,667	$3.64
$ 5.01 – 6.82	466,000	$6.82	2.6	310,667	$6.82
$ 1.86 – 6.82	**5,327,051**	**$3.52**	**2.6**	**3,542,053**	**$3.40**

(c) Restricted stock unit plan

The Company has a restricted stock unit plan that allows the board of directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted stock unit plan, each restrictive share award have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant.

For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. The weighted average fair value of awards granted for the year ended December 31, 2016 was $3.44 (2015 - $2.77) per share award. On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards:

	Number of awards
Outstanding, January 1, 2015	406,500
Granted	1,459,000
Exercised	(4,333)
Outstanding, December 31, 2015	1,861,167
Granted	1,214,000
Exercised	(12,000)
Outstanding, December 31, 2016	**3,063,167**
Exercisable, December 31, 2016	**746,445**

19. Commitments and contingencies:

(a) Commitments

The following table summarizes the Company's commitments at December 31, 2016:

	2017	2018	2019	2020	2021	2022	2023
Office lease	641,312	541,718	541,718	262,535	–	–	–
Flow-through shares	2,500,000	–	–	–	–	–	–
Take or pay commitments[(1)]	985,500	985,500	–	–	–	–	–
Rental fee[(2)]	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	9,296,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 24 months.

(2) Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $119,000 per month for a maximum period of 90 months starting in January 2016 relating to four additional facilities.

(b) Contingencies

The Company, in the normal course of operations, will occasionally become subject to a variety of legal and other claims. Management and the Company's legal counsel evaluate all claims and as necessary, access management's best estimate of costs, if any, to satisfy such claims.

20. Subsequent event:

On January 11, 2017, Tamarack closed the previously announced arrangement agreement (the "Arrangement Agreement") pertaining to the Viking Acquisition. The Viking Acquisition builds upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. Under the terms of the Arrangement Agreement, Tamarack issued an aggregate of 90.1 million common shares and paid $57.3 million in cash. Tamarack also assumed Spur's net debt, estimated to be $25.7 million as at November 30, 2016, after accounting for proceeds from the exercise of all outstanding options of Spur, and severance and transaction costs. Any variance in net debt from the $25.7 million at November 30, 2016, as compared to the final amount determined at closing will adjust the purchase price. Based upon Tamarack's share price on the date of closing being January 11, 2017 of $3.44 per share, the total consideration payable by Tamarack, including the assumption of debt, will be approximately $393.0 million.

Based on the successful completion of the Viking Acquisition on January 11, 2017 the Company's revolving credit facility was adjusted to $200 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. All other terms and conditions of the previous facility remained intact.