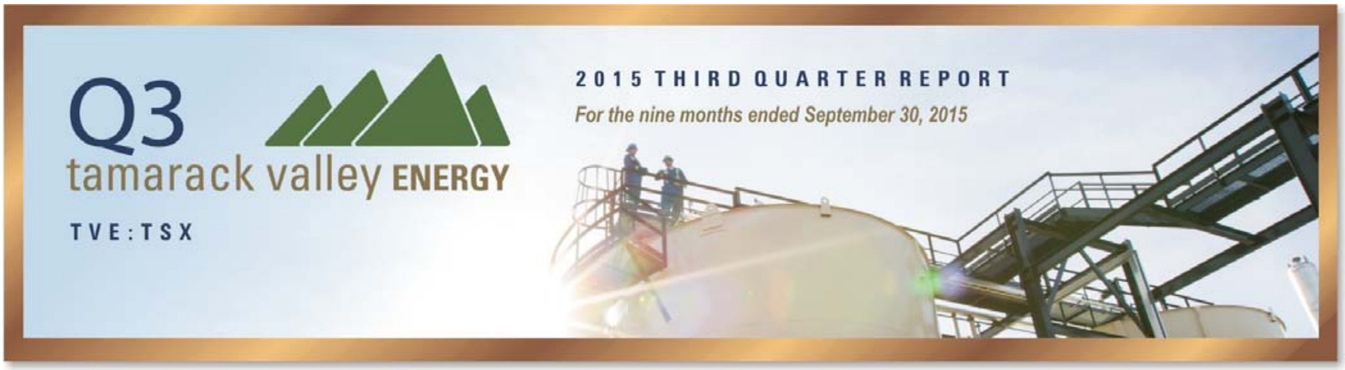

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

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 three and nine months ended September 30, 2015 and 2014. This MD&A is dated and based on information available on November 10, 2015 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and nine months ended September 30, 2015 and 2014. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

The condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS and additional IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to section entitled "Non-IFRS and Additional IFRS Measures" on pages 15 and 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 ("NI 51–101"). 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 resource 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 development oil locations that are economic at various oil prices focused primarily in the Cardium fairway and the Viking fairway in Alberta. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue to deliver on its promise to maximize shareholder return while managing its balance sheet.

Late in the second quarter of 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 $55.0 million, prior to closing adjustments (the "Alder Flats Acquisition").

The Alder Flats Acquisition is accretive to Tamarack and bolsters the Company's strategic Cardium focused land position in the greater Wilson Creek area where the Company's wells have achieved some of the highest production rates in the area. The Alder Flats Acquisition, which closed on June 15, 2015, added 128 (88 net) total sections of land in the greater Wilson Creek / Alder Flats area. On the acquired lands, the Company has identified a total of 70 net economically viable drilling locations, including 40 net high quality Cardium drilling locations that would be expected to pay out in one year or less at current prices. The Alder Flats Acquisition also added approximately 1,450 boe/d (45% oil & NGLs) of production, including strategic midstream assets consisting of a 100% interest in a 1,000 bbl/d oil battery, a 100% interest in a 6 mmcf/d gas plant and over 220 km of pipeline infrastructure.

Production

	Three months ended September 30,			Nine months ended September 30,		
	2015	2014	% change	**2015**	2014	% change
Production						
Light oil (bbls/d)	**3,499**	3,040	15	**3,517**	2,649	33
Heavy oil (bbls/d)	**660**	346	91	**595**	204	192
Natural gas liquids (bbls/d)	**890**	302	195	**663**	225	195
Natural gas (mcf/d)	**22,005**	12,462	77	**18,962**	11,868	60
Total (boe/d)	**8,717**	5,765	51	**7,935**	5,056	57
Percentage of oil and natural gas liquids	**58%**	64%		**60%**	61%	

Average production for the third quarter of 2015 increased by 51% to 8,717 boe/d from 5,765 boe/d in the third quarter of 2014. Compared to the second quarter of 2015, production in the third quarter of 2015 increased by 25% from 6,992 boe/d. The production increase was mainly the result of a full quarter of production from the Alder Flats Acquisition, which added 1,542 boe/d to the quarter average and 8 (7.6 net) Cardium oil wells coming on stream during the quarter adding 971 boe/d. This was partially offset by normal declines from existing production and TransCanada ("TCPL") pipeline restrictions and resulting third party curtailments, which resulted in approximately 387 boe/d of lost production to the quarter average.

Average crude oil and natural gas liquids production in the third quarter of 2015 increased 21% to 5,049 bbls/d compared to 4,163 bbls/d in the second quarter of 2015. The production increase was mainly the result of a full quarter of production from the Alder Flats Acquisition, which added 626 bbls/d to the quarter average and 8 (7.6 net) Cardium oil wells coming on stream during the quarter adding 865 bbls/d. This was partially offset by normal declines from existing production and curtailments which resulted in approximately 59 bbls/d of lost production to the quarter average.

Tamarack's oil and natural gas liquids weighting decreased to 58% of total production in the third quarter of 2015 compared to 60% during the second quarter of 2015, mainly as a result of a full quarter of production from the Alder Flats Acquisition which had 45% oil & NGLs weighting. The Company expects its oil and natural gas liquids weighting to fluctuate between 53% and 62% depending on the timing of production additions from the Wilson Creek area, where production will be weighted higher to liquids content, as compared to the Alder Flats and Brazeau areas, which have a higher natural gas weighting.

Natural gas production averaged 22,005 mcf/d in the third quarter of 2015 compared to 16,972 mcf/d in the second quarter of 2015. The production increase was mainly the result of a full quarter of production from the Alder Flats Acquisition, which added 5,501 mcf/d to the quarter average and 8 (7.6 net) Cardium oil wells coming on stream during the quarter adding 634 mcf/d. This was partially offset by normal declines from existing production and TCPL curtailments which resulted in approximately 1,795 mcf/d of lost production to the quarter average.

Increases in production for the three and nine months ended September 30, 2015, when compared to the same period in 2014, were due to production from assets acquired in the Wilson Creek area of Alberta (the "Wilson Creek Acquisition") in September 2014, assets acquired as part of the Alder Flats Acquisition in the second quarter of 2015, and the successful 2014 and 2015 drilling programs, offset by expected declines from existing production.

During the third quarter of 2015 the Company brought on production 7.6 net Cardium horizontal oil wells in the Wilson Creek area. In addition, the Company has 7 (5.3 net) wells drilled and completed and waiting to be brought on production. All 7 wells are expected to come on in late November or early December.

Production in October 2015, based on field estimates, was approximately 9,440 boe/d (58% oil & NGLs).

Petroleum, Natural Gas Sales and Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2015	2014	% change	**2015**	2014	% change
Revenue						
Oil and NGLs	**$21,625,992**	$30,597,130	(29)	**$63,267,241**	$77,709,845	(19)
Natural gas	**6,153,327**	4,736,126	30	**15,153,254**	14,443,931	5
Total	**$27,779,319**	$35,333,256	(21)	**$78,420,495**	$92,153,776	(15)
Average realized price						
Light oil ($/bbl)	**54.39**	95.83	(43)	**54.06**	96.62	(44)
Heavy oil ($/bbl)	**49.15**	77.59	(37)	**47.31**	77.59	(39)
Natural gas liquids ($/bbl)	**13.78**	47.74	(71)	**20.28**	57.28	(65)
Combined average oil and NGLs ($/boe)	**46.56**	90.19	(48)	**48.53**	92.49	(48)
Natural gas ($/mcf)	**3.04**	4.13	(26)	**2.93**	4.46	(34)
Revenue $/boe	**34.64**	66.62	(48)	**36.20**	66.77	(46)
Edmonton Par (Cdn$/bbl)	**54.66**	97.72	(44)	**58.65**	100.46	(42)
Hardisty Heavy (Cdn$/bbl)	**44.32**	84.38	(47)	**48.13**	86.32	(44)
AECO daily index (Cdn$/mcf)	**2.89**	4.00	(28)	**2.76**	4.77	(42)
AECO monthly index (Cdn$/mcf)	**2.77**	4.20	(34)	**2.79**	4.53	(38)
Royalty expenses	**$3,051,720**	$4,701,831	(35)	**$8,000,773**	$11,862,719	(33)
$/boe	**3.81**	8.87	(57)	**3.69**	8.60	(57)
percent of sales	**11**	13	(15)	**10**	13	(23)

Revenue from crude oil, natural gas and associated natural gas liquids sales increased by 10% to $27,779,319 in the third quarter of 2015 from $25,330,543 in the second quarter of 2015 and 21% lower than the $35,333,256 in the third quarter of 2014. Natural gas prices averaged $3.04/mcf and the combined oil and natural gas liquids prices averaged $46.56/bbl in the third quarter of 2015 as compared to $2.80/mcf and $55.47/bbl in the second quarter of 2015 and $4.13/mcf and $90.19/bbl in the third quarter of 2014, respectively.

The 10% increase to revenue during the third quarter of 2015, when compared to the second quarter of 2015, was as a result of a 21% increase in crude oil and natural gas liquids production, a 30% increase in natural gas production and a 9% increase in natural gas prices, partially offset by a 16% decrease in crude oil and natural gas liquids pricing.

The 21% decrease in revenue in the third quarter of 2015, compared to the third quarter of 2014, was primarily caused by a 48% decrease in crude oil and natural gas liquids pricing and a 26% decrease in natural gas prices, partially offset by a 37% increase in crude oil and natural gas liquids production and a 77% increase in natural gas production.

The 15% decrease to revenue in the first nine months of 2015, compared to the first nine months of 2014, was primarily caused by a 48% decrease in crude oil and natural gas liquids pricing and a 34% decrease in natural gas prices, partially offset by a 55% increase in crude oil and natural gas liquids production and a 60% increase in natural gas production.

The Company's realized crude oil prices for the three and nine months ended September 30, 2015 and 2014 generally correlate to the Edmonton Par price posting for the same period. Natural gas liquids are priced at varying discounts to Edmonton Par price posting depending on market conditions, pipeline capacity and the season. Natural gas liquids prices decreased by a greater margin than did the Edmonton Par price due to higher than normal propane inventories in Western Canada. The Company expects this trend to remain consistent for the remainder of 2015.

The Company's realized heavy oil price for the three and nine months ended September 30, 2015 and 2014 generally correlate to the Hardisty Heavy price for the same periods.

The Company's realized natural gas prices for the three and nine months ended September 30, 2015, generally correlate to the AECO daily index pricing, but may not always correlate to the AECO monthly index pricing. The reason for the variance is that in periods of rapid price increases or declines, a portion of the Company's sales, which are based mainly on the daily index, will not correlate to the monthly index.

At September 30, 2015, the Company held derivative commodity contracts aggregated as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $78.58
Crude oil	500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.52
Crude oil	1,900 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.23
Crude oil	700 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.86
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21
Crude oil	1,200 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $76.86
Crude oil	900 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $74.99
Natural gas	5,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.06
Natural gas	5,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.06

At September 30, 2015, the commodity contracts were fair valued with an asset of $12,431,194 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized gain of $3,960,284 recorded in earnings for the nine months ended September 30, 2015.

At September 30, 2015, 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, 2016 – March 31, 2016	AECO fixed price	Cdn $3.02

Royalty expenses for the third quarter of 2015 were $3.81/boe or $3,051,720, representing 11% of revenue, compared to royalty expenses for the second quarter of 2015 of $3.45/boe or $2,192,889, representing 9% of revenue. The increase in royalties as a percentage of revenue in the third quarter of 2015 as compared to the second quarter of 2015, was related to the full quarter impact of the legacy production from the Alder Flats Acquisition whose royalty rate was approximately 18%. The Company expects royalty rates to fluctuate as commodity prices change.

The royalty expenses for the third quarter of 2014 were $8.87/boe or $4,701,831, representing 13% of revenue. The decrease in royalties as a percentage of revenue in the third quarter of 2015, as compared to the third quarter of 2014, was related to lower commodity prices and the impact of lower royalties on wells drilled in late 2014 and 2015, partially offset by the higher royalty rates from the wells acquired by the Company on September 30, 2014 in the Wilson Creek Acquisition and June 15, 2015 in the Alder Flats Acquisition.

Royalty expenses for the first nine months of 2015 were $3.69/boe or $8,000,773, representing 10% of revenue, compared to royalty expenses for the first nine months of 2014 of $8.60/boe or $11,862,719, representing 13% of revenue. The decrease in royalties as a percentage of revenue in the first nine months of 2015, as compared to the first nine months of 2014, was related to lower commodity prices and the impact of lower royalties on wells drilled in late 2014 and 2015, partially offset by the higher royalty rates from the wells acquired by the Company on September 30, 2014 in the Wilson Creek Acquisition and June 15, 2015 in the Alder Flats Acquisition.

The Company expects royalty rates to remain lower in 2015 compared to those realized in 2014 due to lower commodity prices.

Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2015	2014	% change	**2015**	2014	% change
Total production expenses	**$11,264,333**	$7,869,691	43	**$28,313,619**	$19,648,222	44
Total ($/boe)	**$14.05**	$14.84	(5)	**$13.07**	$14.24	(8)

Production expenses for the third quarter of 2015 were $14.05/boe compared to $12.43/boe incurred during the second quarter of 2015. The production expenses on a per boe basis increased by $1.62/boe in the third quarter of 2015 as a result of the initial costs associated with the integration of the assets from the Alder Flats Acquisition, the full quarter effect of the higher operating cost assets from the Alder Flats Acquisition, and higher trucking and treating costs at the Hatton field while modifications were being made at the facility to handle higher production volumes. An optimization debottlenecking project was commenced in Alder Flats in the third quarter and is expected to be completed by the end of Q1/16, which should return Company operating costs to $12.00-$12.50/boe. On a dollar basis, overall costs increased in the third quarter of 2015 by 43% to $11,264,333 from the $7,909,969 incurred during the second quarter of 2015. The increase in total production costs resulted from the 25% increase in production and the increase in per unit cost.

Total production expenses on a boe basis were $14.05/boe in the third quarter of 2015 compared to $14.84/boe during the third quarter of 2014. Production expenses for the three months ended September 30, 2015 increased by 43% to $11,264,333, compared to $7,869,691 in the same period in 2014. The decrease in total production costs, on a per boe basis, resulted from the acquisition of the lower per unit cost Wilson Creek properties. On a dollar basis, overall costs increased as a result of a 51% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

Total production expenses on a boe basis were $13.07/boe in the first nine months of 2015 compared to $14.24/boe during the same period in 2014. Production expenses for the nine months ended September 30, 2015 increased by 44% to $28,313,619, compared to $19,648,222 in the same period in 2014. The decrease in total production costs, on a per boe basis, resulted from the acquisition of the lower per unit cost Wilson Creek properties. On a dollar basis, overall costs increased as a result of a 57% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

Operating Netback

($/boe)	Three months ended September 30, 2015	2014	% change	Nine months ended September 30, 2015	2014	% change
Average realized sales	**34.64**	66.62	(48)	**36.20**	66.77	(46)
Royalty expenses	**(3.81)**	(8.87)	(57)	**(3.69)**	(8.60)	(57)
Production expenses	**(14.05)**	(14.84)	(5)	**(13.07)**	(14.24)	(8)
Operating field netback	**16.78**	42.91	(61)	**19.44**	43.93	(56)
Realized commodity hedging gain (loss)	**5.35**	(2.03)	364	**4.61**	(2.95)	256
Operating netback	**22.13**	40.88	(46)	**24.05**	40.98	(41)

The operating netback for the third quarter of 2015 decreased by 19% to $22.13/boe compared to $27.17/boe during the second quarter of 2015. The decrease was the result of a 16% decrease in oil and natural gas liquids prices ($46.56/bbl versus $55.47/bbl) and a 13% increase in operating expense per boe ($14.05/boe versus $12.43/boe), partially offset by a realized hedging gain of $5.35/boe during the third quarter of 2015, compared to a realized hedging gain of $3.23/boe during the second quarter of 2015.

The operating netback for the third quarter of 2015 decreased by 46% to $22.13/boe compared to $40.88/boe during the third quarter of 2014. The decrease was the result of a 48% decrease in oil and natural gas liquids prices ($46.56/bbl versus $90.19/bbl) and a 26% decrease in natural gas prices ($3.04/mcf versus $4.13/mcf), partially offset by a decrease of 57% in royalty expenses per boe ($3.81/boe versus $8.87/boe), a realized hedging gain of $5.35/boe during the third quarter 2015 compared to a $2.03/boe realized hedging loss during the third quarter of 2014 and a 5% decrease in operating expense per boe ($14.05/boe versus $14.84/boe).

The operating netback for the first nine months of 2015 decreased by 41% to $24.05/boe compared to $40.98/boe during the first nine months of 2014. The decrease was the result of a 48% decrease in oil and natural gas liquids prices ($48.53/bbl versus $92.49/bbl) and a 34% decrease in natural gas prices ($2.93/mcf versus $4.46/mcf), partially offset by a decrease of 57% in royalty expenses per boe ($3.69/boe versus $8.60/boe), a realized hedging gain of $4.61/boe during the third quarter 2015 compared to a $2.95/boe realized hedging loss during the third quarter of 2014 and an 8% decrease in operating expense per boe ($13.07/boe versus $14.24/boe).

General and Administrative Expenses

	Three months ended September 30, 2015	2014	% change	Nine months ended September 30, 2015	2014	% change
Gross costs	**$2,176,842**	$2,178,671	(0)	**$6,840,598**	$5,805,576	18
Capitalized costs and recoveries	**(443,419)**	(428,118)	4	**(1,381,798)**	(1,222,895)	13
General and administrative costs	**$1,733,423**	$1,750,553	(1)	**$5,458,800**	$4,582,681	19
Total ($/boe)	**$2.16**	$3.30	(35)	**$2.52**	$3.32	(24)

General and administrative expenses for the third quarter of 2015 were $2.16/boe on costs of $1,733,423 compared to $2.60/boe on costs of $1,652,686 in the second quarter of 2015. While overall costs increased by 5% in the third quarter of 2015 due to costs associated to the Alder Flats Acquisition, the costs per unit decreased by 17% during the third quarter of 2015 due to a 25% increase in production.

General and administrative expenses for the third quarter of 2014 were $3.30/boe on costs of $1,750,553. The 35% decrease in the cost per boe in the third quarter of 2015 was the result of the impact of the 51% increase in production without adding any incremental general and administrative expenses.

General and administrative expenses for the first nine months of 2015 were $2.52/boe on costs of $5,458,800 compared to $3.32/boe on costs of $4,582,681 during the same period in 2014. While overall costs increased to $5,458,800 for the first nine months of 2015 due to Tamarack's expanded operations, the costs per unit decreased 24% in the first nine months of 2015 due to the 57% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses of $699,933 and $2,297,279, relating to the preferred shares, stock options and restricted share awards for the three and nine months ended September 30, 2015, compared to $890,858 and $2,011,064 for the same periods in 2014. Stock-based compensation expense is calculated based on graded vesting periods that are front end loaded.

The Company capitalized $338,013 and $1,132,209 of stock-based compensation expenses relating to exploration and development activities for the three and nine months ended September 30, 2015, compared to capitalizing $370,581 and $869,017 for the same periods in 2014.

For the three months ended September 30, 2015 the Company issued 100,000 options at a weighted average exercise price of $2.62 per share and issued 18,000 restricted stock units. For the nine months ended September 30, 2015 the Company issued 157,000 options at a weighted average exercise price of $3.19 per share and issued 43,000 restricted stock units.

For the nine months ended September 30, 2015, 65,416 preferred shares were exchanged for 12,742 common shares on a cashless settlement basis and 29,167 stock options at $3.60 per share were exercised for total gross proceeds of $105,001.

Interest

Interest expense was $1,387,002 and $4,043,972 for the three and nine months ended September 30, 2015, compared to $686,006 and $1,502,398 for the same periods in 2014. The Company has drawn $94,423,028 on its revolving credit facility at September 30, 2015, compared to $100,274,534 drawn on its line at September 30, 2014. Interest expense was higher for the three and nine months ended September 30, 2015 and compared to the same time period in 2014 due to a higher average amount drawn year-over-year on the revolving credit facility. The average amount drawn over the nine months in 2015 has been approximately $97 million as compared to an average amount drawn of approximately $53 million in 2014.

Depletion, Depreciation, Amortization and Accretion

The Company depleted 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.

	Three months ended September 30,			Nine months ended September 30,		
	2015	2014	% change	**2015**	2014	% change
Depletion and depreciation	**$13,901,611**	$11,195,137	24	**$43,165,433**	$28,220,277	53
Amortization of undeveloped leases	**172,483**	813,738	(79)	**568,000**	2,378,068	(76)
Accretion	**267,592**	156,540	71	**708,614**	451,648	57
Total	**$14,341,686**	$12,165,415	18	**$44,442,047**	$31,049,993	43
Depletion and depreciation ($/boe)	**$17.34**	$21.11	(18)	**$19.93**	$20.45	(3)
Amortization ($/boe)	**0.22**	1.53	(86)	**0.26**	1.72	(85)
Accretion ($/boe)	**0.33**	0.30	10	**0.33**	0.33	0
Total ($/boe)	**$17.89**	$22.94	(22)	**$20.52**	$22.50	(9)

Depletion, depreciation, amortization, and accretion expense on a boe basis for the third quarter of 2015 was 17% lower at $17.89/boe, compared to $21.55/boe during the second quarter of 2015. The third quarter 2015 decrease in depletion, depreciation, amortization, and accretion expense rate as compared to the second quarter of 2015 was a result of the increased percentage of overall production related to the lower cost Cardium oil properties as a result of the Alder Flats Acquisition. Depletion, depreciation, amortization and accretion expense for the third quarter of 2015 was $14,341,686, compared to $13,711,122 during the second quarter of 2015. The 5% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 25% increase in production partially offset by lower per unit depletion, depreciation and accretion expense on a boe basis. The reason for the reduction in the per boe rate to $17.89/boe from $21.55/boe was due to the internally estimated reserve additions as a result of the 2015 Cardium horizontal drilling in Wilson Creek, better than expected production performance in Hatton and the 10-20% reduction in future development capital.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the third quarter of 2015 was $17.89/boe, compared to $22.94/boe during the third quarter of 2014. Depletion, depreciation, amortization, and accretion expense for the third quarter of 2015 was $14,341,686, compared to $12,165,415 during the third quarter of 2014. The third quarter 2015 decrease in depletion, depreciation, amortization, and accretion expense rate as compared to the third quarter of 2014 was a result of the lower amortization rate and the increased percentage of overall production related to the lower cost Cardium and heavy oil properties. The 18% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 51% increase in production, partially offset by lower per unit depletion, depreciation and accretion expense on a boe basis.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the first nine months of 2015 was $20.52/boe, compared to $22.50/boe during the first nine months of 2014. Depletion, depreciation, amortization, and accretion expense for the first nine months of 2015 was $44,442,047, compared to $31,049,993 during the first nine months of 2014. The decrease in depletion, depreciation, amortization, and accretion expense rate was the result of the lower amortization rate. The 43% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 57% increase in production, partially offset by lower per unit depletion, depreciation and accretion expense on a boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three and nine months ended September 30, 2015, nor does it expect to pay any cash taxes in 2015 or in 2016 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and nine months ended September 30, 2015, a deferred income tax recovery of $2,929,781 and $8,065,362 was recognized, compared to a deferred income tax expense of $2,557,428 and $5,275,236 for the same periods in 2014. There was a deferred tax recovery during the three and nine months ended September 30, 2015 due to a loss before taxes, while in the same periods of 2014 a deferred tax expense was recorded due to income before taxes being recognized.

On June 29, 2015, the general corporate income tax rate for Alberta increased to 12% from 10% effective July 1, 2015.

Funds from Operations and Net Income

	Three months ended September 30,			Nine months ended September 30,		
	2015	**2014**	% change	**2015**	**2014**	% change
Petroleum and natural gas sales	**$27,779,319**	$35,333,256	(21)	**$78,420,495**	$92,153,776	(15)
Royalties	**(3,051,720)**	(4,701,831)	35	**(8,000,773)**	(11,862,719)	33
Realized gain (loss) on financial instruments	**4,288,134**	(1,074,942)	499	**9,987,577**	(4,072,738)	345
Production expenses	**(11,264,333)**	(7,869,691)	(43)	**(28,313,619)**	(19,648,222)	(44)
General and administration expenses	**(1,733,423)**	(1,750,553)	1	**(5,458,800)**	(4,582,681)	(19)
Transaction costs	**(12,791)**	(3,441,352)	100	**(1,044,308)**	(3,441,352)	70
Interest	**(1,387,002)**	(686,006)	(102)	**(4,043,972)**	(1,502,398)	(169)
Funds from operations	**$14,618,184**	$15,808,881	(8)	**$41,546,600**	$47,043,666	(12)

Funds from operations during the third quarter of 2015 were $14,618,184 ($0.15 per share basic and diluted) compared to funds from operations of $13,185,630 ($0.16 per share basic and diluted) for the second quarter of 2015. The increase in funds from operations is primarily the result of a 25% increase in production, a higher realized hedging gain and the $1,031,517 in transactions costs associated with the Alder Flats Acquisition during the second quarter of 2015, partially offset by the 16% decrease in crude oil and natural gas liquids pricing and higher royalty and operating expense.

Funds from operations during the three months ended September 30, 2015 were $14,618,184 ($0.15 per share basic and diluted), compared to funds from operations of $15,808,881 ($0.26 per share basic and $0.25 per share diluted) for the same period in 2014. The decrease in funds from operations was primarily the result of the 48% decrease in crude oil and natural gas liquids pricing, a 26% decrease in natural gas pricing, higher interest expense and higher production expenses related to the increased production, partially offset by a realized hedging gain in the third quarter of 2015 compared to a realized hedging loss in the third quarter of 2014 and a 51% increase in production and lower royalty expenses.

Funds from operations during the first nine months of 2015 were $41,546,600 ($0.47 per share basic and diluted), compared to funds from operations of $47,043,666 ($0.81 per share basic and $0.79 per share diluted) for the same period in 2014. The decrease in funds from operations was primarily the result of the 48% decrease in crude oil and natural gas liquids pricing, a 34% decrease in natural gas pricing, higher interest expense and higher production expenses related to the increased production, partially offset by a realized hedging gain in the first nine months of 2015 compared to a realized hedging loss in the first nine months of 2014 and a 57% increase in production and lower royalty expenses.

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2015**	**2014**	% change	**2015**	**2014**	% change
Petroleum and natural gas sales	**$34.64**	$66.62	(48)	**$36.20**	$66.77	(46)
Royalties	**(3.81)**	(8.87)	57	**(3.69)**	(8.60)	57
Realized gain (loss) on financial instruments	**5.35**	(2.03)	364	**4.61**	(2.95)	256
Production expenses	**(14.05)**	(14.84)	5	**(13.07)**	(14.24)	8
General and administration expenses	**(2.16)**	(3.30)	35	**(2.52)**	(3.32)	24
Transaction costs	**(0.02)**	(6.49)	100	**(0.48)**	(2.49)	81
Interest	**(1.73)**	(1.29)	(34)	**(1.87)**	(1.09)	(71)
Funds from operations	**18.23**	29.81	(39)	**$19.18**	$34.09	(44)

Funds from operations on a per boe basis decreased in the third quarter of 2015 to $18.23/boe from $20.72/boe in the second quarter of 2015 due to the 16% decrease in crude oil and natural gas liquids pricing and higher per unit royalty and operating expenses, partially offset by a higher realized hedging gain, lower general and administrative expenses and the $1.62/boe in transactions costs associated with the Alder Flats Acquisition that occurred during the second quarter of 2015.

The Company had a net loss of $15,063,870 ($0.15 per share basic and diluted) during the three months ended September 30, 2015, compared to a net loss of $2,141,787 ($0.03 per share basic and diluted) for the second quarter of 2015. The Company recorded a higher net loss for the three months ended September 30, 2015 as compared to the second quarter of 2015 as a result of an impairment to property, plant and equipment, a 16% decrease in crude oil and natural gas liquids pricing, higher production costs due to a 25% increase in production and a 14% increase in expenses on a per boe basis, partially offset by an unrealized gain on financial instruments taken in the third quarter of 2015 as compared to an unrealized loss in the second quarter of 2015 and transactions costs associated with the Alder Flats Acquisition that were incurred in the second quarter of 2015.

The Company had a net loss of $15,063,870 ($0.15 per share basic and diluted) during the three months ended September 30, 2015, compared to net income of $6,790,587 ($0.11 per share basic and share diluted) for the same period in 2014. The Company recorded a net loss for the three months ended September 30, 2015 as compared to net income from the same period in 2014 as a result of an impairment to property, plant and equipment, a 48% decrease in crude oil and natural gas liquids pricing, a 26% decrease in natural gas pricing, higher depletion, depreciation, amortization, and accretion expense, a lower gain on the disposition of property, plant and equipment and higher production expenses related to the increased production, partially offset by a higher unrealized hedging gain in the third quarter of 2015 as compared to the third quarter of 2014, a deferred income tax recovery in the third quarter of 2015 as compared to a deferred tax expense in the third quarter of 2014 and a 51% increase in production.

The Company had a net loss of $22,447,287 ($0.26 per share basic and diluted) during the nine months ended September 30, 2015, compared to net income of $13,823,840 ($0.24 per share basic and $0.23 per share diluted) for the same period in 2014. The Company recorded a net loss for the nine months ended September 30, 2015 as compared to the same period in 2014 as a result of an impairment to property, plant and equipment, a 48% decrease in crude oil and natural gas liquids pricing, a 34% decrease in natural gas pricing, higher depletion, depreciation, amortization, and accretion expense, a gain on the disposition of property, plant and equipment in 2014 and higher production expenses related to the increased production, partially offset by a higher unrealized hedging gain in 2015 as compared to 2014, a deferred income tax recovery in 2015 as compared to a deferred tax expense in 2014 and a 57% increase in production.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
	2015	2014	% change	**2015**	2014	% change
Land	1,172	$217,579	(99)	**$412,716**	$2,940,187	(86)
Geological and geophysical	45,486	393,529	(88)	**52,995**	684,966	(92)
Drilling and completion	15,253,544	27,416,874	(44)	**28,068,238**	80,509,114	(65)
Equipment and facilities	6,548,911	6,595,543	(1)	**14,059,263**	15,903,942	(12)
Capitalized G&A	228,275	(44,029)	(618)	**712,687**	641,655	11
Office equipment	150,336	7,929	1,796	**151,821**	45,729	232
Total capital expenditures	**$22,227,724**	$34,587,425	(36)	**$43,457,720**	$100,725,593	(57)
Property acquisition	**1,230,258**	166,056,562	(99)	**55,403,908**	166,056,562	(67)
Proceeds from disposal of property, plant and equipment	**(292,354)**	(4,269,237)	(93)	**(2,247,937)**	(4,653,090)	(52)
Total net capital expenditures	**$23,165,628**	$196,374,750	(88)	**$96,613,691**	$262,129,065	(63)

During the third quarter of 2015, the Company equipped 2 (2.0 net) previously drilled and completed horizontal Cardium wells, drilled, completed and equipped 2 (2.0 net) horizontal Cardium wells, drilled and completed 2 (1.6 net) horizontal Cardium oil wells and drilled 2 (1.8 net) horizontal Cardium oil well all in the Wilson Creek/Alder Flats area. The Company also began debottlenecking infrastructure in the recently acquired Alder Flats area in order to optimize operations by increasing capacity and by reducing operating costs. This project will be ongoing throughout the rest of this year and completed by the end of the first quarter of 2016.

Since the end of the second quarter of 2015, the Company has closed four minor tuck-in acquisitions in the Wilson Creek area, one in the third quarter and three in the fourth quarter. Total costs, before adjustments, were $3,112,000, adding approximately 103 boe/d of production and 35.75 (3.64 net) sections of prospective lands.

On July 29, 2015, the Company reduced its 2015 capital expenditure budget by 6.5%-11.6% to between $71 and $76 million (excluding the cost of the Alder Flats Acquisition) in response to WTI crude oil falling to US $45/bbl. Tamarack is prepared to adjust its capital budget to account for future changes in commodity prices as the year progresses in order to preserve capital and generate an expedited return on future capital deployed.

2015 Drilling Summary (including wells spudded by September 30, 2015)		
	Gross	Net
Cardium	11.0	10.5
Total	11.0	10.5

For the three months ended September 30, 2015, the Company disposed of its interest in a certain oil and gas property for $292,354. There was approximately 65 boe/d of production associated with the property at the time sale. The Company will continue to pursue disposition of non-core assets.

The Company's net undeveloped land was 215,150 acres at the end of the third quarter of 2015.

Impairment

At September 30, 2015, the recoverable amounts of the Cash Generating Units ("CGUs") were estimated as the fair value less costs to sell based on the net present value of the before tax cash flows from oil and natural gas proved plus probable reserves estimated by the Company discounted at rates of 8% to 15%. The prices used to estimate fair value less costs to sell are the average of those used by three independent industry reserve companies. Due mainly to continuing negative volatility in oil and natural gas prices offset partially by reductions to future costs, it was determined that the net book value of certain oil and natural gas producing CGUs exceeded the recoverable amount and the Company has recognized a $29,100,000 (2014 – $56,290,000) impairment charge. The impairment charges are mainly related to the dramatic decrease in commodity prices which have been factored into the third party reserve evaluator's crude oil and natural gas price forecasts. As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods.

CGU	Impairment	Recoverable Value
Quaich	491,000	4,371,000
Hanlan	712,000	–
Minor Properties	561,000	–
Viking Oil	26,647,000	43,655,000
Peace River Arch	689,000	2,123,000

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $105,837,205 at September 30, 2015. Tamarack's net debt at September 30, 2014 was $121,684,316 and at December 31, 2014 was $129,798,673. During the first nine months of 2015, the Company reduced net debt by $23,961,468 improving financial flexibility. Tamarack's net debt at September 30, 2015 to annualized funds from operations in the third quarter of 2015 was 1.8 times, compared to 1.9 times at September 30, 2014 and 1.7 times at December 31, 2014.

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 at $3.78 per share for total gross proceeds of $9,750,699.

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.

During the nine months ended September 30, 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.

At September 30, 2015 and November 10, 2015, there were 99,933,725 common shares, 1,110,584 preferred shares, 4,140,551 options and 449,500 restricted share awards outstanding. At December 31, 2014 there were 77,928,466 common shares, 1,176,000 preferred shares, 4,147,386 options and 406,500 restricted share awards outstanding. The Company had 99,933,725 and 87,532,408 weighted average basic common shares outstanding during the three and nine months ended September 30, 2015.

At September 30, 2015, the Company had a revolving credit facility in the amount of $155,000,000 and a $10,000,000 operating facility (collectively the “Facility”).The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 27, 2017. 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 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 scheduled mid-year review is to take place during the fourth quarter of 2015.

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. The Company is in compliance of all of its covenants.

With the recent decrease in commodity prices and continued volatility in the oil and gas industry, Tamarack’s strategy remains focused on preserving its balance sheet by adjusting capital spending relative to changes in commodity prices. The Company wants to maintain flexibility with its balance sheet to be opportunistic and take advantage of potential tuck-in acquisition opportunities within its core areas while commodity prices are low. Tamarack will focus on drilling wells that target a return on capital cost payout of 1.5 years or less. Tamarack will also continue to focus on reducing capital and operating costs in order to preserve capital efficiencies.

2015 Guidance

On May 14, 2015, the Company, in conjunction with the Alder Flats Acquisition, announced a revised 2015 capital budget and 2015 guidance based on an Edmonton Par price average of $63.00/bbl and an AECO price average of $2.60/GJ.

The 2015 capital budget and guidance was announced as follows:

- $76-$86 million capital program in addition to the $55 million Alder Flats Acquisition (total $130-$140 million)
- Production to average between 8,000-8,200 boe/d (approximately 58-62% oil & NGLs)
- Exit production rate of approximately 10,000 boe/d (approximately 58-62% oil & NGLs)

On July 29, 2015, as a result of the 15% decrease in oil prices, Tamarack announced a reduction in capital spending for the remainder of 2015. The Company reduced its capital program by 6.5% to 11.6% to between $70 and $75 million, from $76 to $86 million. This resulting capital program was based on a WTI price of $45.00/bbl, Edmonton Par price of $53.50/bbl, an AECO price of $2.75/GJ and a $0.77 Canadian dollar for the second half of 2015.

The current 2015 capital budget and guidance is as follows:

- $70-$75 million capital program in addition to the $55 million Alder Flats Acquisition (total $125-$130 million)
- Production to average between 8,000-8,200 boe/d (approximately 55-60% oil & NGLs)
- Exit production rate between 9,200-9,500 boe/d (approximately 55-60% oil & NGLs)
- Exit debt to Q4/15 annualized funds from operations is expected to be 1.75 times based on the above commodity price assumptions

During the first nine months of 2015, Tamarack focused on reducing debt to maintain financial flexibility. Tamarack is prepared to adjust its capital budget to account for changes in commodity prices as the year progresses in order to preserve capital and ensure an accretive return on future capital deployed.

On November 10, 2015, the Company announced the following production guidance increases:

- Production to average between 8,200-8,300 boe/d (approximately 55-60% oil & NGLs)
- Exit production rate between 9,500-9,700 boe/d (approximately 55-60% oil & NGLs)

Commitments

The following table summarizes the Company's commitments at September 30, 2015:

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease (1)	179,475	418,178	99,594	–	–	–	–	–
Take or pay commitments (2)	248,400	988,200	985,500	985,500	–	–	–	–
Drilling commitments (3)	12,760,000	9,240,000	9,000,000	–	–	–	–	–
Rental fee (4)	935,535	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	1,871,063
Total	14,123,410	14,388,503	13,827,219	4,727,625	3,742,125	3,742,125	3,742,125	1,871,063

1. Office lease commitments.
2. Pipeline commitment to deliver a minimum of 1,887 bbls/d of crude oil/condensate subject to a take-or-pay provision of $1.43/bbl. During the nine month period ended September 30, 2015, the Company delivered an average of 1,560 bbls/d of liquids through this pipeline. The remaining term is 37 months.
3. Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 to 20 net wells must be drilled by December 31, 2016, provided the Company gets access to certain lands that are currently restricted from access due to regulatory conditions. As of September 30, 2015, the Company had satisfied approximately 39% to 52% of the drilling commitment. The Company estimates the capital expenditures to fulfill the remainder of this commitment will be $22 to $40 million. The table above represents the average expected commitment.
4. Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities.

Non–IFRS and Additional IFRS Measures

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds generated from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also 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) **Funds from Operations -** Tamarack's method of calculating funds from operations may differ from other companies, and therefore may not be comparable to measures used by other companies. Tamarack calculates funds from operations as cash flow from operating activities, as determined under IFRS, before the changes in non-cash working capital related to operating activities and abandonment expenditures, as the Company believes the uncertainty surrounding the timing of collection, payment or incurrence of these items makes them less useful in evaluating Tamarack's operating performance. Tamarack uses funds from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Funds from operations per share have been calculated using the same basic and diluted weighted average share amounts used in earnings per share calculations. A summary of this reconciliation is presented as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Cash provided by operating activities	**$11,738,543**	$17,498,523	**$37,939,616**	$45,414,752
Abandonment expenditures	**(233)**	136,739	**154,574**	411,907
Changes in non-cash working capital	**2,879,874**	(1,826,381)	**3,452,410**	1,217,007
Funds from operations	**$14,618,184**	$15,808,881	**$41,546,600**	$47,043,666
Funds from operation per share -basic	**$ 0.15**	$ 0.26	**$ 0.47**	$ 0.81
Funds from operation per share -diluted	**$ 0.15**	$ 0.25	**$ 0.47**	$ 0.79

(b) **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 6 in the section titled "Operating Netback."

(c) **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):

	September 30, 2015	December 31, 2014
Cash and cash equivalents	$ –	$830,104
Accounts receivables	16,138,038	20,370,676
Prepaid expenses	885,431	810,983
Accounts payable and accrued liabilities	(28,437,646)	(51,610,436)
Bank debt	(94,423,028)	(100,200,000)
Net debt	$(105,837,205)	$(129,798,673)

Selected Quarterly Information

Three months ended	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013
Sales volumes								
Natural gas *(mcf/d)*	**22,005**	16,972	17,864	17,518	12,462	12,033	11,093	10,349
Oil and NGLs *(bbls/d)*	**5,049**	4,163	5,115	4,761	3,688	3,197	2,333	2,611
Average boe/d *(6:1)*	**8,717**	6,992	8,092	7,681	5,765	5,203	4,182	4,336
Product prices								
Natural gas *($/mcf)*	**3.04**	2.80	2.91	3.91	4.13	4.37	4.93	3.72
Oil and NGLs *($/bbl)*	**46.56**	55.47	48.33	62.87	90.19	94.65	93.23	77.78
Oil equivalent *($/boe)*	**34.64**	39.82	34.75	47.89	66.62	68.27	65.09	55.72
(000s, except per share amounts)								
Financial results								
Gross revenues	**27,779**	25,331	25,311	33,839	35,333	32,322	24,498	22,224
Funds from operations	**14,618**	13,186	13,743	19,128	15,809	17,790	13,445	10,505
Per share – basic	**0.15**	0.16	0.18	0.25	0.26	0.29	0.26	0.24
Per share – diluted	**0.15**	0.16	0.18	0.25	0.25	0.29	0.25	0.23
Net income (loss)	**(15,064)**	(2,142)	(5,242)	(38,991)	6,791	5,243	1,791	10,855
Per share – basic	**(0.15)**	(0.03)	(0.07)	(0.50)	0.11	0.09	0.03	0.37
Per share – diluted	**(0.15)**	(0.03)	(0.07)	(0.50)	0.11	0.08	0.03	0.37
Additions to property and equipment, net of proceeds	**21,936**	14,246	5,028	26,774	30,318	40,742	25,012	22,010
Net property acquisitions	**1,230**	54,174	–	–	166,057	–	–	–
Corporate acquisitions	–	–	–	–	–	–	–	57,135
Total assets	**549,652**	561,977	482,227	497,578	525,003	319,065	288,608	269,707
Working capital (deficiency)[1]	**(105,837)**	(97,280)	(121,159)	(129,799)	(121,684)	(59,490)	(37,130)	(81,764)
Bank debt[2]	**94,423**	88,500	112,951	100,200	100,275	43,735	17,494	71,796
Decommissioning obligations	**61,808**	64,883	45,340	41,357	36,732	20,956	20,484	19,802
Deferred income tax (asset)	**(35,770)**	(33,647)	(28,802)	(27,299)	(16,870)	(17,743)	(19,681)	(19,467)

(1) Excluding fair value of financial instruments

(2) The debt Facility was previously demand and included in the working capital deficiency

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 affects the mark-to-market calculation, which results in swings in earnings.
- The recorded impairment charges on the Company's oil and natural gas related CGUs due to falling oil and gas prices in the amount of $29,100,000 in the third quarter of 2015 and $56,290,000 in the fourth quarter of 2014.
- On June 15, 2014, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta.
- 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.
- Oil volumes have continued to grow due to successful drilling at Lochend, Garrington, Greater Pembina area, Redwater and Hatton, and from the Wilson Creek Acquisition and the acquisition of Sure Energy Inc. on October 9, 2013 (the "Sure Acquisition"). At the same time, the oil and natural gas liquids weighting has decreased from 60% of total production in the fourth quarter of 2013 to 58% in the third quarter of 2015.
- On August 19, 2013, the Company entered into a farm-in agreement with an industry major to earn a 70% working interest in up to 113 net sections of prospective Cardium lands directly offsetting proven ongoing development projects in the greater Pembina area.
- In 2013, the Sure Acquisition added $4,214,745 to oil and natural gas revenue and contributed $239,547 to net income.
- The Company recorded a $10,053,750 gain on the Sure Acquisition for Q4 2013 as the fair value paid was less than the fair value of the assets acquired.
- The Company recorded $1,031,517 in transaction costs in the second quarter of 2015 related the Alder Flats Acquisition, $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition and $1,645,116 in transaction costs in the fourth quarter of 2013 related to the Sure Acquisition.

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 Natural 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 shares 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.

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 forecasted. 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 completing technology.

Insurance is in place to protect against major asset destruction or business interruption, including well blow-outs and pollution. In addition, Tamarack cultivates long-term 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.

The Alberta government is in the process of conducting a royalty review which could impact the amount of royalties payable in the future.

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", "project", "potential", "targeting", "intend", “want”, "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:

- Estimated production rates in 2015.
- Debottlenecking of infrastructure in the Wilson Creek / Alder Flats area.
- Adjustments to the capital budget to account for commodity price changes.

- Future operating costs on a boe basis.
- Reduction of operating costs on the assets purchased in the Alder Flats Acquisition.
- Future impairment charges related to CGU's
- Tamarack's focus on reducing capital costs.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- The interest rates under Tamarack's credit facilities.
- Future capital expenditures and capital program funding.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas weighting in 2015.
- Expectations as to royalty rates in 2015.
- The ability of the Company to take advantage of opportunities that may arise due to commodity price volatility.
- Disposition of non-core assets.

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;
- the realization of anticipated benefits of acquisitions, including 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 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 revised Annual Information Form for the year ended December 31, 2014, which may be accessed on Tamarack's SEDAR profile at www.sedar.com.

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.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)

	September 30, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ –	$830,104
Accounts receivable	16,138,038	20,370,676
Prepaid expenses and deposits	885,431	810,983
Fair value of financial instruments (note 3)	12,431,194	8,470,910
	29,454,663	30,482,673
Property, plant and equipment (note 5)	481,820,117	435,328,116
Exploration and evaluation assets (note 7)	2,606,425	4,468,823
Deferred tax asset	35,770,440	27,298,825
	$549,651,645	$497,578,437
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$28,437,646	$51,610,436
Bank debt (note 12)	94,423,028	100,200,000
Decommissioning obligations (note 8)	61,807,916	41,356,532
Shareholders' equity:		
Share capital (note 10)	415,923,954	336,086,662
Contributed surplus	16,112,939	12,931,358
Deficit	(67,053,838)	(44,606,551)
	364,983,055	304,411,469
Commitments and contingencies (note 14)		
	$549,651,645	$497,578,437

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
For the three and nine months ended September 30, 2015 and 2014
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2015	2014	2015	2014
Revenue:				
Oil and natural gas	$27,779,319	$35,333,256	$78,420,495	$92,153,776
Royalties	(3,051,720)	(4,701,831)	(8,000,773)	(11,862,719)
Realized gain (loss) on financial instruments (note 3)	4,288,134	(1,074,942)	9,987,577	(4,072,738)
Unrealized gain on financial instruments (note 3)	11,297,903	3,362,512	3,960,284	2,985,456
	40,313,636	32,918,995	84,367,583	79,203,775
Expenses:				
Production	11,264,333	7,869,691	28,313,619	19,648,222
General and administration	1,733,423	1,750,553	5,458,800	4,582,681
Transaction costs	12,791	3,441,352	1,044,308	3,441,352
Stock-based compensation (note 13)	699,933	890,858	2,297,279	2,011,064
Finance	1,654,594	842,546	4,752,586	1,954,046
Depletion, depreciation and amortization	14,074,094	12,008,875	43,733,433	30,598,345
Loss (gain) on disposition of property, plant and equipment (note 5)	(231,881)	(3,232,895)	180,207	(2,131,011)
Impairment of property, plant and equipment (note 6)	29,100,000	–	29,100,000	–
	58,307,287	23,570,980	114,880,232	60,104,699
Income (loss) before taxes	(17,993,651)	9,348,015	(30,512,649)	19,099,076
Deferred income tax recovery (expense)	2,929,781	(2,557,428)	8,065,362	(5,275,236)
Net Income (loss) and comprehensive income (loss)	$(15,063,870)	$6,790,587	$(22,447,287)	$13,823,840
Net income (loss) per share (note 11):				
Basic	$(0.15)	$ 0.11	$(0.26)	$ 0.24
Diluted	$(0.15)	$ 0.11	$(0.26)	$ 0.23

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Equity
(unaudited)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2014	46,168,718	$157,974,725	$9,487,596	$(19,439,190)	148,023,131
Issue of common shares	30,479,748	176,404,941	–	–	176,404,941
Issue of flow-through shares	1,280,000	10,048,000			10,048,000
Share issue costs, net of tax of $2,769,148	–	(8,307,445)	–	–	(8,307,445)
Transfer on exercise of stock options and preferred shares	–	862,441	(862,441)	–	–
Flow-through share premium	–	(896,000)	–	–	(896,000)
Stock-based compensation	–	–	4,306,203	–	4,306,203
Net loss	–	–	–	(25,167,361)	(25,167,361)
Balance at December 31, 2014	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	2,186,800	9,075,220	–	–	9,075,220
Share issue costs, net of tax of $1,215,369	–	(3,537,078)	–	–	(3,537,078)
Transfer on exercise of stock options and preferred shares	–	247,906	(247,906)	–	–
Flow-through share premium	–	(809,116)	–	–	(809,116)
Stock-based compensation	–	–	3,429,487	–	3,429,487
Net loss	–	–	–	(22,447,287)	(22,447,287)
Balance at September 30, 2015	99,933,725	$415,923,954	$16,112,939	$(67,053,838)	$364,983,055

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2014	46,168,718	$157,974,725	$9,487,596	$(19,439,190)	$148,023,131
Issue of common shares	30,429,748	176,242,441	–	–	176,242,441
Issue of flow-through shares	1,280,000	10,048,000	–	–	10,048,000
Share issue costs, net of tax of $2,678,324	–	(8,034,972)	–	–	(8,034,972)
Transfer on exercise of stock options and preferred shares	–	753,943	(753,943)	–	–
Flow-through share premium	–	(896,000)	–	–	(896,000)
Stock-based compensation	–	–	2,880,081	–	2,880,081
Net income	–	–	–	13,823,840	13,823,840
Balance at September 30, 2014	77,878,466	$336,088,137	$11,613,734	$(5,615,350)	$342,086,521

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2015 and 2014
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2015	2014	2015	2014
Cash provided by (used in):				
Operating:				
Net income (loss)	$(15,063,870)	$6,790,587	$(22,447,287)	$13,823,840
Items not involving cash:				
Depletion, depreciation and amortization	14,074,094	12,008,875	43,733,433	30,598,345
Stock-based compensation	699,933	890,858	2,297,279	2,011,064
Loss (gain) on disposition of property, plant and equipment	(231,881)	(3,232,895)	180,207	(2,131,011)
Accretion expense on decommissioning obligations	267,592	156,540	708,614	451,648
Unrealized gain on financial instruments	(11,297,903)	(3,362,512)	(3,960,284)	(2,985,456)
Impairment of property, plant and equipment	29,100,000	–	29,100,000	–
Deferred income tax expense (recovery)	(2,929,781)	2,557,428	(8,065,362)	5,275,236
Funds from operations	14,618,184	15,808,881	41,546,600	47,043,666
Abandonment expenditures (note 8)	233	(136,739)	(154,574)	(411,907)
Changes in non-cash working capital (note 9)	(2,879,874)	1,826,381	(3,452,410)	(1,217,007)
Cash provided by operating activities	11,738,543	17,498,523	37,939,616	45,414,752
Financing:				
Change in bank debt	5,923,028	56,540,023	(5,776,972)	28,478,589
Proceeds from issuance of shares	–	125,245,036	83,935,580	186,290,441
Share issue costs	(9,845)	(6,737,091)	(4,752,447)	(10,713,296)
Cash provided by financing activities	5,913,183	175,047,968	73,406,161	204,055,734
Investing:				
Property, plant and equipment additions	(22,158,281)	(10,495,837)	(43,239,213)	(54,778,333)
Exploration and evaluation additions	(69,443)	(24,091,588)	(218,507)	(45,947,260)
Acquisitions	(1,230,258)	(166,056,562)	(56,213,342)	(166,056,562)
Proceeds from disposal of property, plant and equipment	292,354	4,269,237	2,247,937	4,653,090
Changes in non-cash working capital (note 9)	2,085,460	3,828,259	(14,752,756)	12,658,579
Cash used in investing activities	(21,080,168)	(192,546,491)	(112,175,881)	(249,470,486)
Change in cash and cash equivalents	(3,428,442)	–	(830,104)	–
Cash and cash equivalents, beginning of period	3,428,442	–	830,104	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is incorporated under the Business Corporations Act of Alberta. The consolidated financial statements of the Company consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp., Tamarack Valley Holdings Corp., Tamarack Valley Partnership and Tamarack Valley Ridge Holdings Ltd. The Company also 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 currently 3100, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7.

2. Basis of preparation:

(a) Statement of compliance:

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standards 34, "Interim Financial Reporting" of International Reporting Standards ("IFRS").

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2014. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2014.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on November 10, 2015.

3. Commodity contracts:

It is the Company's policy to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 published forward price curves

3. Commodity contracts (continued):

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 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.

At September 30, 2015, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	2,500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $78.58	$3,743,119
Crude oil	500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.52	$904,022
Crude oil	1,900 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.23	$2,204,347
Crude oil	700 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.86	$1,130,938
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21	$2,395,201
Crude oil	1,200 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $76.86	$1,137,445
Crude oil	900 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $74.99	$588,303
Natural gas	5,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.06	$187,471
Natural gas	5,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.06	$140,348
					$12,431,194

At September 30, 2015, the commodity contracts were fair valued with an asset of $12,431,194 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized gain of $3,960,284 recorded in earnings for the nine months ended September 30, 2015.

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 September 30, 2015, 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, 2016 – March 31, 2016	AECO fixed price	Cdn $3.02

3. Commodity contracts (continued):

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	**September 30, 2015**	December 31, 2014
Risk management contracts		
Current asset	**$12,431,194**	$8,470,910
Current liability	–	–
Balance, end of the period	**$12,431,194**	$8,470,910

4. Property Acquisition:

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 $55.0 million, prior to closing adjustments. 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 $1,031,517, which were expensed through the statement of income and comprehensive income.

The allocation of the purchase price is as follows:

Cash Consideration:		
Total consideration	$	54,983,084
Net Assets Acquired:		
Prepaid expenses	$	809,434
Property, plant and equipment		61,641,980
Decommissioning obligations		(7,468,330)
Net assets	$	54,983,084

The above amounts are estimates, which were made by management at the time of preparation of these financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized.

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%.

4. Property Acquisition (continued):

If the Alder Flats properties had been acquired on January 1, 2015, the incremental oil and natural gas revenue and income recognized for the period ended September 30, 2015 and the pro forma results would have been as follows:

Period ended June 30, 2015	As stated	Alder Flats Prior to acquisition	Pro Forma
Oil and natural gas revenue	$78,420,495	$7,855,791	$86,276,286
Net income	(22,447,287)	(1,568,330)	(24,015,617)

5. Property, plant and equipment:

	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2014	$275,426,366	$276,670	$275,703,036
Property acquisition	173,606,620	–	173,606,620
Cash additions	59,854,564	55,814	59,910,378
Decommissioning costs	14,499,800	–	14,499,800
Stock-based compensation	1,327,975	–	1,327,975
Transfer from exploration and evaluation assets	97,227,381	–	97,227,381
Disposals	(36,448,859)	–	(36,448,859)
Balance at December 31, 2014	585,493,847	332,484	585,826,331
Property acquisition	63,826,183	–	63,826,183
Cash additions	43,087,392	151,821	43,239,213
Decommissioning costs	11,844,186	–	11,844,186
Stock-based compensation	1,132,208	–	1,132,208
Transfer from exploration and evaluation assets	1,512,905	–	1,512,905
Disposals	(2,928,641)	–	(2,928,641)
Balance at September 30, 2015	$703,968,080	$484,305	$704,452,385
Depletion, depreciation and impairment losses:			
Balance at January 1, 2014	$54,270,113	$121,163	$54,391,276
Depletion and depreciation	44,784,177	56,413	44,840,590
Transfer from exploration and evaluation assets	2,460,234	–	2,460,234
Disposals	(7,483,885)	–	(7,483,885)
Impairment loss	56,290,000	–	56,290,000
Balance at December 31, 2014	150,320,639	177,576	150,498,215
Depletion and depreciation	43,118,925	46,508	43,165,433
Disposals	(131,380)	–	(131,380)
Impairment loss	29,100,000	–	29,100,000
Balance at September 30, 2015	$222,408,184	$224,084	$222,632,268

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2014	$435,173,208	$154,908	$435,328,116
At September 30, 2015	$481,559,896	$260,221	$481,820,117

For the nine months ended September 30, 2015 the Company disposed of its interest in certain oil and gas properties for $2,247,937.

5. Property, plant and equipment (continued):

The calculation of depletion at September 30, 2015 includes estimated future development costs of $346,309,000 (December 31, 2014 – $374,258,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $26,338,000 (December 31, 2014 – $23,400,000).

6. Impairment loss:

At September 30, 2015, due to continuing negative volatility in natural gas and oil prices, reserve revisions and adjustments to future costs, the Company determined that triggers were present on all of its CGU's. The Company tested its CGU's, for impairment. The recoverable amounts of the Company's CGU's were estimated as the fair value less costs to sell based on the net present value of the before tax cash flows from oil and gas proved plus probable reserves estimated by the Company discounted at rates of 10% to 15%. The prices used to estimate fair value less costs to sell are the average of those used by three independent industry reserve companies. It was determined that the net book value of the following exceeded the recoverable amount and the Company recognized $29,100,000 in impairment charges (December 31, 2014 - $56,290,000).

CGU	Impairment	Recoverable Value
Quaich	491,000	4,371,000
Hanlan	712,000	–
Minor Properties	561,000	–
Viking Oil	26,647,000	43,655,000
Peace River Arch	689,000	2,123,000
Total	29,100,000	50,149,000

The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at September 30, 2015, as forecasted by the independent external reserves evaluators:

	2015	2016	2017	2018	2019	2020	2021	2022	Thereafter
WTI (US$/bbl)[1]	53.33	62.07	66.67	71.33	74.77	78.24	81.75	85.37	+1.8%/yr
Edmonton Par (Cdn$/bbl)[1]	57.49	61.24	69.31	73.95	77.88	81.22	85.29	89.43	+1.8%/yr
AECO (Cdn$/MMbtu)[1]	2.94	3.50	3.75	4.05	4.32	4.53	4.69	4.87	+1.8%/yr

(1) Price forecast, effective September 30, 2015.

7. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2014	$26,814,629
Additions	94,043,801
Transfer to property, plant and equipment	(97,227,381)
Balance at December 31, 2014	23,631,049
Additions	218,507
Transfer to property, plant and equipment	(1,512,905)
Balance at September 30, 2015	$22,336,651
Amortization and impairment:	
Balance at January 1, 2014	$15,158,239
Amortization	2,987,449
Exploration and evaluation impairment	3,476,772
Transfer to property, plant and equipment	(2,460,234)
Balance at December 31, 2014	19,162,226
Amortization	568,000
Balance at September 30, 2015	$ 19,730,226

	Total
Carrying amounts:	
At December 31, 2014	$4,468,823
At September 30, 2015	$2,606,425

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, 2014 the Company recognized an impairment of $3,476,772 related to an exploratory oil play that would be uneconomic at current oil prices.

8. 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 $62.1 million at September 30, 2015 (December 31, 2014 – $43.0 million), which is expected to be incurred between 2015 and 2038. A risk-free rate of 2.2% (2014 – 2.5%) and an inflation rate of 2% (2014 – 2%) is used to calculate the fair value of the decommissioning obligations at September 30, 2015 as presented in the table below:

	September 30, 2015	December 31, 2014
Balance, beginning of the period	**$41,356,532**	$19,801,991
Liabilities incurred	**728,080**	3,504,114
Liabilities acquired	**8,422,275**	7,550,058
Change in estimates	**444,130**	3,224,957
Change in discount rate on acquisition	**10,671,976**	7,770,729
Expenditures	**(154,574)**	(678,886)
Liabilities disposed	**(369,117)**	(540,597)
Accretion	**708,614**	724,166
Balance, end of the period	**$61,807,916**	$41,356,532

The decommissioning obligations acquired in the Alder Flats Acquisition 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 resulted from the decommissioning obligations being revalued using the risk-free rate of 2.2% as at September 30, 2015 a decrease from the risk-free rate of 2.5% used on December 31, 2014.

9. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Source/(use of cash):				
Accounts receivable	**$(399,885)**	$(2,865,084)	**$4,232,638**	$(6,104,381)
Prepaid expenses and deposits	**(63,082)**	(81,050)	**$(74,448)**	(228,028)
Accounts payable and accrued liabilities	**(331,447)**	8,600,774	**(23,172,790)**	17,773,981
Working capital acquired on acquisition	**–**	–	**809,434**	–
	$(794,414)	$5,654,640	**$(18,205,166)**	$11,441,572
Related to operating activities	**$(2,879,874)**	$1,826,381	**$(3,452,410)**	$(1,217,007)
Related to investing activities	**2,085,460**	3,828,259	**$(14,752,756)**	$12,658,579

10. Share capital:

At September 30, 2015 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

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 at $3.78 per share for total gross proceeds of $9,750,699. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $9,075,220 of qualifying oil and natural gas expenditures effective December 31, 2015. As of September 30, 2015 the Company has incurred the full amount of qualifying oil and natural gas expenditures.

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.

During the nine months ended September 30, 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.

11. Income (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	**2015**	2014
Net income (loss) for the period	**$(15,063,870)**	$6,790,587	**$(22,447,287)**	$13,823,840
Weighted average shares - basic	**99,933,725**	61,423,738	**87,532,408**	58,140,697
Weighted average shares - diluted	**99,933,725**	63,509,567	**87,532,408**	59,872,353
Net income (loss) per share-basic	**$(0.1500)**	$ 0.11	**$(0.26)**	$ 0.24
Net income (loss) per share-diluted	**$(0.1500)**	$ 0.11	**$(0.26)**	$ 0.23

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2015, 5,700,635 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive. For the three and nine months ended September 30, 2014, 506,000 and 1,031,000 stock options and preferred shares were excluded from the diluted earnings per share as they were anti-dilutive.

12. Bank debt:

At September 30, 2015, the Company had a revolving credit facility in the amount of $155 million and a $10 million operating facility (collectively the "Facility"). The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 27, 2017. 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 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 scheduled review is to take place during the fourth quarter of 2015.

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.

At September 30, 2015, the Company had utilized the Facility in the amount of $94.4 million and the Company was compliant with its working capital ratio at 3.1 to 1.0.

As at September 30, 2015, the Company had letter of guarantees outstanding in the amount of $43,980 against the Facility.

13. Share-based payments:

(a) Preferred share plan:

As at September 30, 2015 there are 1,110,584 (December 31, 2014 – 1,176,000) 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 nine month period ended September 30, 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 9,993,373 options or restricted share units to its employees, directors and consultants of which 5,182,781 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

13. Share-based payments (continued):

the date of grant. There were 157,000 options granted during the nine month period ended September 30, 2015.

The fair value of each option granted during the period 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:

	Nine months ended September 30, 2015	Year ended December 31, 2014
Risk free rate (%)	**0.69**	1.39
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**2.03**	3.57

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

	Number of options	Weighted average exercise price
Outstanding, January 1, 2014	3,164,551	$ 2.92
Granted	1,223,000	5.49
Exercised	(173,498)	2.57
Forfeited	(66,667)	2.39
Outstanding, December 31, 2014	4,147,386	$ 3.70
Granted	157,000	3.19
Exercised	(29,167)	3.60
Forfeited	(134,668)	3.25
Outstanding, September 30, 2015	**4,140,551**	**$ 3.71**

The following table summarizes information about stock options outstanding and exercisable at September 30, 2015:

	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	1,183,051	$2.16	2.2	992,701	$2.08
$ 3.01 – 5.00	2,491,500	$3.86	3.0	955,831	$3.94
$ 5.01 – 6.82	466,000	$6.82	3.9	155,333	$6.82
$ 1.86 – 6.82	**4,140,551**	**$3.71**	**2.8**	**2,103,865**	**$3.28**

13. Share-based payments (continued):

(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 entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of 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 nine months ended September 30, 2015 was $3.52 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 at September 30, 2015:

	Number of awards
Outstanding, December 31, 2014	406,500
Granted	43,000
Outstanding, September 30, 2015	**449,500**

14. Commitments and contingencies:

(a) Commitments

The following table summarizes the Company's commitments at September 30, 2015:

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease (1)	179,475	418,178	99,594	–	–	–	–	–
Take or pay commitments (2)	248,400	988,200	985,500	985,500	–	–	–	–
Drilling commitments (3)	12,760,000	9,240,000	9,000,000	–	–	–	–	–
Rental fee (4)	935,535	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	1,871,063
Total	14,123,410	14,388,503	13,827,219	4,727,625	3,742,125	3,742,125	3,742,125	1,871,063

1. Office lease commitments.

2. 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 40 months.

3. Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 to 20 net wells must be drilled by December 31, 2016, provided the Company gets access to certain lands that are currently restricted from access due to regulatory conditions. As of September 30, 2015, the Company had satisfied approximately 39% to 52% of the drilling commitment. The Company estimates the capital expenditures to fulfill the remainder of this commitment will be $22 to $40 million. The table above represents the average expected commitment.

4. Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities.

14. Commitments and contingencies (continued):

(b) Contingencies

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

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(1)(2)(3)

Dean Setoguchi(1)(3)

David Mackenzie(1)(2)

Jeff Boyce(2)(3)

Brian Schmidt

(1) Member of Audit Committee of the Board of Directors
(2) Member of the Reserves Committee of the Board of Directors
(3) Member of the Compensation & Governance Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Noralee Bradley
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Osler, Hoskin & Harcourt LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange

Stock symbol: TVE

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