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 six months ended June 30, 2016 and 2015. This MD&A is dated and based on information available on August 10, 2016 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and six months ended June 30, 2016 and 2015. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

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.

About Tamarack

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

Strategic Acquisitions Completed Subsequent to the Second Quarter

Subsequent to the end of the quarter, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny / Redwater Acquisition") on July 12, 2016 and July 25, 2016, respectively. The assets in Penny are comprised of a light oil pool under waterflood with low recoveries, low decline rates, plus strategic infrastructure, while the Redwater and Wilson Creek assets included 95 (60 net) sections of land and significant strategic infrastructure. The combined total purchase price for the Penny / Redwater Acquisition was $85 million, and included approximately 1,900 boe/d of predominantly light oil and natural gas liquids production. The Company closed a bought deal financing on July 12, 2016 raising gross proceeds of $81.6 million which provided the primary funding for the Penny / Redwater Acquisition.

Production

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Production						
Light oil (bbls/d)	**3,482**	3,029	15	**3,642**	3,525	3
Heavy oil (bbls/d)	**410**	627	(35)	**410**	563	(27)
Natural gas liquids (bbls/d)	**1,067**	507	110	**1,067**	548	95
Natural gas (mcf/d)	**27,462**	16,972	62	**26,640**	17,415	53
Total (boe/d)	**9,536**	6,992	36	**9,559**	7,539	27
Percentage of oil and natural gas liquids	**52%**	60%		**54%**	61%	

Tamarack achieved strong production results for the first half of 2016, averaging 9,559 boe/d for the period, which is at the upper end of the Company's guidance range of 9,100 to 9,600 boe/d. Better than expected capital efficiencies and higher than expected production results from wells drilled to date in 2016 contributed to volumes that nearly exceeded guidance, despite having over 400 boe/d of unexpected production curtailments that occurred during the second quarter. The Company expects to average 9,800 to 10,500 boe/d for the second half of 2016 and exit 2016 at approximately 11,000 boe/d due to production additions associated with the Penny / Redwater Acquisition and a modest second half drilling program. See page 13 for a more comprehensive summary of the updated 2016 guidance.

Average production of 9,536 boe/d in the second quarter of 2016 was maintained from the previous quarter of 9,582 boe/d. Second quarter volumes were positively impacted by a combined 1,950 boe/d attributable to a full quarter of production from five (4.3 net) Cardium oil wells and one (0.8 net) Manville liquids-rich gas well which came on stream late in the first quarter, plus the impact of one (1.0 net) 2-mile horizontal Cardium oil well that was brought on stream late in the second quarter. These production increases were offset by normal declines from existing production, plus approximately 427 boe/d of lost production due to TransCanada pipeline ("TCPL") curtailments and production downtime associated with non-operated properties during the quarter.

Crude oil and natural gas liquids production in the second quarter of 2016 averaged 4,959 bbls/d, a decrease of 6% compared to the first quarter 2016 production of 5,279 bbls/d. A combined 926 bbls/d were added due to a full quarter of production from five (4.3 net) Cardium oil wells and one (0.8 net) Manville liquids-rich gas well which came on stream late in the first quarter, and one (1.0 net) 2-mile horizontal Cardium oil well that was brought on stream late in the second quarter. However, these production additions were offset by normal declines from existing production and approximately 120 bbls/d of lost production attributable to TCPL curtailments during the period.

Tamarack's oil and natural gas liquids weighting was 52% of total production in the second quarter of 2016 compared to 55% for the first quarter of 2016, largely due to the impact on production from a liquids-rich Mannville gas well drilled in the first quarter which increased the natural gas weighting in the second quarter. For 2016, the Company expects its oil and natural gas liquids weighting to fluctuate between 50% and 55% depending on the timing of production additions from its higher liquids-weighted areas of Wilson Creek, Redwater and Penny, compared to additions coming from the higher natural gas-weighted areas of Alder Flats and Brazeau. Oil and natural gas weightings may also be affected by production additions associated with future drilling of liquids-rich Mannville gas wells in the Wilson Creek area.

Natural gas production averaged 27,462 mcf/d in the second quarter of 2016, an increase of 6% over the 25,818 mcf/d produced in the prior quarter. The increase was primarily due to associated gas production from the five (4.3 net) Cardium oil wells and one (0.8 net) Manville liquids-rich gas well which came on stream late in the first quarter, and one (1.0 net) Cardium oil well that was brought on stream in the second quarter, which added a combined 7,381 mcf/d to the period's production average. Volume increases from drilling were partially offset by normal declines from existing production coupled with lost production in the quarter due to TCPL curtailments and production downtime associated with non-operated properties which totaled approximately 1,842 mcf/d.

Compared to the prior year, second quarter 2016 production of 9,536 boe/d was 36% higher than 6,992 boe/d in the same period in 2015. This increase is attributable to the successful 2016 first quarter drilling program which positively impacted second quarter 2016 volumes, as well as the impact of a full quarter of production from assets acquired in the Wilson Creek area of Alberta during the second quarter of 2015 (the "Wilson Creek / Alder Flats Acquisition"), partially offset by expected declines from existing production.

Average production for the six months ended June 30, 2016 was 9,559 boe/d, 27% higher than the 7,539 boe/d produced during the same period in 2015. The increase is attributable to the successful 2016 first quarter drilling program, as well as the impact of a full period of production from the Wilson Creek / Alder Flats Acquisition, partially offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Revenue						
Oil and NGLs	**$20,460,447**	$21,012,854	(3)	**$35,303,771**	$41,641,249	(15)
Natural gas	**4,056,541**	4,317,689	(6)	**8,831,876**	8,999,927	(2)
Total	**$24,516,988**	$25,330,543	(3)	**$44,135,647**	$50,641,176	(13)
Average realized price						
Light oil ($/bbl)	**52.16**	61.21	(15)	**44.34**	53.89	(18)
Heavy oil ($/bbl)	**37.31**	51.73	(28)	**30.09**	46.21	(35)
Natural gas liquids ($/bbl)	**21.57**	25.87	(17)	**16.81**	25.63	(34)
Combined average oil and NGLs ($/boe)	**45.35**	55.47	(18)	**37.90**	49.62	(24)
Natural gas ($/mcf)	**1.62**	2.80	(42)	**1.82**	2.86	(36)
Revenue $/boe	**28.25**	39.82	(29)	**25.37**	37.11	(32)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**55.01**	68.49	(20)	**45.91**	60.59	(24)
Hardisty Heavy (Cdn$/bbl)	**42.09**	57.41	(27)	**33.43**	50.07	(33)
AECO daily index (Cdn$/mcf)	**1.39**	2.65	(47)	**1.61**	2.70	(40)
AECO monthly index (Cdn$/mcf)	**1.24**	2.66	(53)	**1.67**	2.80	(40)
Royalty expenses	**$1,048,997**	$2,192,889	(52)	**$2,829,359**	$4,949,053	(43)
$/boe	**1.21**	3.45	(65)	**1.63**	3.63	(55)
percent of sales	**4**	9	(56)	**6**	10	(40)

Revenue from crude oil, natural gas and associated natural gas liquids sales was $24,516,988 in the second quarter of 2016, which was 25% higher than the $19,618,659 generated in the first quarter of 2016 and 3% lower than the $25,330,543 generated in the second quarter of 2015. The 25% increase in second quarter 2016 revenue over the previous quarter is attributable to crude oil and natural gas liquids prices that were 47% higher, partially offset by a 20% decrease in natural gas prices. The second quarter 2016 revenue decreased 3% relative to the same period in 2015 primarily due to 18% lower crude oil and natural gas liquids prices and 42% lower natural gas prices, partially offset by a 36% increase in production volumes. Revenue in the first half of 2016 declined 13% compared to the first half of 2015, primarily caused by a 24% decrease in crude oil and natural gas liquids pricing and a 36% decrease in natural gas prices, partially offset by a 27% increase in production volumes.

Tamarack's realized prices for natural gas and the combined oil and natural gas liquids averaged $1.62/mcf and $45.35/bbl in the second quarter of 2016, compared to $2.03/mcf and $30.90/bbl in the first quarter of 2016 and $2.80/mcf and $55.47/bbl in the second quarter of 2015.

The realized crude oil prices for the three and six months ended June 30, 2016 and 2015 generally correlate to the posted Edmonton Par price for those periods. Natural gas liquids are priced at varying discounts to the posted Edmonton Par price depending on market conditions, pipeline capacity and seasonality. Natural gas liquids prices decreased by a greater margin than the Edmonton Par price due to high North American supply and inventory combined with warmer winter conditions which led to lower than normal propane demand. The Company expects the high supply and inventory trend to remain consistent for the balance of 2016.

The Company's realized heavy oil price for the three and six months ended June 30, 2016 and 2015 generally correlate to the Hardisty Heavy price for those periods.

For the three and six months ended June 30, 2016, Tamarack's realized natural gas prices generally correlate to AECO daily index pricing, however variances can arise during periods of rapid price increases or decreases, because the portion of the Company's sales that are based mainly on the daily index will not correlate to the monthly index.

At June 30, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,800 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $69.92
Crude oil	2,000 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.43
Crude oil	1,700 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $59.15
Crude oil	1,700 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $60.24
Crude oil	800 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $63.73
Natural gas	3,000 GJ/day	July 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53
Natural gas	9,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.31
Natural gas	10,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.64
Natural gas	12,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.37
Natural gas	12,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.41
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79

At June 30, 2016, the commodity contracts were fair valued in a liability position of $2,519,089 (December 31, 2015 - $12,468,101 asset) recorded on the balance sheet resulting in an unrealized loss of $14,987,190 recorded in earnings.

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 June 30, 2016, the Company held physical commodity contracts as follows.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	July 1, 2016 – September 30, 2016	AECO fixed price	Cdn $2.44
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

Royalty expenses for the second quarter of 2016 were $1.21/boe or $1,048,997, representing 4% of revenue, compared to $2.04/boe or $1,780,362 for the first quarter of 2016, representing 9% of revenue. The $0.83/boe decrease in royalties in the second quarter of 2016 compared to the first quarter of 2016 was related to the Company's annual gas cost allowance adjustment that is difficult to predict in advance from year to year. Excluding the realized benefit of the annual gas cost allowance adjustment, royalty rates as a percent of revenue would have been 8% during the second quarter of 2016.

Royalties as a percentage of revenue were lower in the second quarter of 2016 compared to the second quarter of 2015, when royalty expenses were $3.45/boe or $2,192,889, representing 9% of revenue. The year over year decrease is due to the sliding scale mechanism which results in lower royalties when commodity prices are low, lower initial royalty rates on wells that were drilled between late 2015 and the first half of 2016, and the Company's annual gas cost allowance adjustment. These positive impacts were partially offset by higher royalty rates from wells acquired in the Wilson Creek / Alder Flats Acquisition in June 2015.

The royalty expense for the first half of 2016 was $1.63/boe or $2,829,359, representing 6% of revenue, compared to $3.63/boe or $4,949,053, representing 10% of revenue for the same period in 2015. The decrease in royalties as a percentage of revenue for the first half of 2016 relative to 2015 is due to the sliding scale mechanism which results in lower royalties when commodity prices are low, lower initial royalty rates on wells that were drilled between late 2015 and the first half of 2016, and the Company's annual gas cost allowance adjustment. These positive impacts were partially offset by higher royalty rates from wells acquired in the Wilson Creek / Alder Flats Acquisition in June 2015. Excluding the realized benefit of the annual gas cost allowance adjustment, royalty rates as a percent of revenue would have been 9% during the first half of 2016.

The Company expects royalty rates to increase in the second half of 2016 compared to first half of 2016 due to the higher royalty rates associated with the assets from the Penny / Redwater Acquisition.

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

Production Expenses

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Total production expenses	**$9,592,542**	$7,909,969	21	**$19,747,300**	$17,049,286	16
Total ($/boe)	**$11.05**	$12.43	(11)	**$11.35**	$12.50	(9)

Production expenses for the second quarter of 2016 decreased by 5% to $11.05/boe compared to $11.65/boe incurred during the first quarter of 2016. The $0.60/boe decrease in the second quarter of 2016 resulted from a combination of several factors, including the full quarter effect of the new oil trucking terminal in Wilson Creek, an optimization debottlenecking project that was completed in Alder Flats in the first quarter of 2016 and the installation of a field compressor diverting Company production away from third party operated facilities into operated facilities. Also contributing to lower operating costs was the continuation of the Company-wide initiative to reduce service costs, plus the Company benefited from new production coming on-stream in the lower-cost Wilson Creek area. On an absolute basis, overall costs decreased in the second quarter of 2016 to $9,592,542 compared to $10,154,758 in the first quarter of 2016, due to the lower cost achievements. The Company expects operating costs to increase during the third quarter of 2016 as a result of the Penny / Redwater Acquisition where per unit operating costs were higher than Tamarack's current rates. The Company will focus efforts on reducing operating costs on the newly acquired assets throughout the second half of 2016 to improve overall netbacks.

On a per unit basis, second quarter of 2016 production expenses were 11% lower than the $12.43/boe realized in the same quarter of 2015, but increased 21% on an absolute basis to $9,592,542, compared to $7,909,969 for the same period in 2015. The lower per boe expenses in 2016 resulted from cost reductions at the Wilson Creek, Alder Flats and Heavy oil properties and from the impact of higher volumes across fixed costs which resulted in lower per unit costs. On an absolute basis, production expenses increased as a result of a 36% increase in production volumes and the impact of facility rental arrangements, partially offset by lower per unit costs.

Production expenses in the first half of 2016 were 9% lower at $11.35/boe compared to $12.50/boe during the same period in 2015, but increased 16% on an absolute basis to $19,747,300, compared to $17,049,286 for the same period in 2015. The lower per boe production expenses in 2016 resulted from cost reductions at the Wilson Creek, Alder Flats and Heavy oil properties and from the impact of higher volumes across fixed costs resulting in lower per unit costs. On an absolute basis, overall costs increased as a result of a 27% increase in production volumes and the impact of facility rental arrangements, partially offset by lower per unit costs.

Operating Netback

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Average realized sales	**28.25**	39.82	(29)	**25.37**	37.11	(32)
Royalty expenses	**(1.21)**	(3.45)	(65)	**(1.63)**	(3.63)	(55)
Production expenses	**(11.05)**	(12.43)	(11)	**(11.35)**	(12.50)	(9)
Operating field netback	**15.99**	23.94	(33)	**12.39**	20.98	(41)
Realized commodity hedging gain (loss)	**4.69**	3.23	45	**5.96**	4.18	43
Operating netback	**20.68**	27.17	(24)	**18.35**	25.16	(27)

Operating netback for the second quarter of 2016 increased by 29% to $20.68/boe compared to $16.04/boe during the first quarter of 2016. This is attributable to a 47% increase in oil and natural gas liquids prices ($45.35/bbl versus $30.90/bbl), a 5% decrease in operating expense per boe ($11.05/boe versus $11.65/boe) and a 41% decrease in royalty expense per boe ($1.21/boe versus $2.04/boe), partially offset by a 20% decrease in natural gas prices ($1.62/mcf versus $2.03/mcf) and a realized hedging gain of $4.69/boe in the second quarter of 2016 compared to $7.23/boe in the first quarter of 2016.

The second quarter 2016 operating netback decreased by 24% compared to $27.17/boe in the second quarter of 2015. This was due to an 18% decrease in oil and natural gas liquids prices ($45.35/bbl versus $55.47/bbl) and a 42% decrease in natural gas prices ($1.62/mcf versus $2.80/mcf), partially offset by royalty expenses per boe that were 65% lower ($1.21/boe versus $3.45/boe), operating expenses that were 11% lower ($11.05/boe versus $12.43/boe) and higher realized hedging gains ($4.69/boe versus $3.23/boe).

The first half of 2016 operating netback decreased by 27% to $18.35/boe as compared to $25.16/boe received for the same period in 2015. This was due to a 24% decrease in oil and natural gas liquids prices ($37.90/bbl versus $49.62/bbl) and a 36% decrease in natural gas prices ($1.82/mcf versus $2.86/mcf), partially offset by royalty expenses per boe that were 55% lower ($1.63/boe versus $3.63/boe), operating expenses that were 9% lower ($11.35/boe versus $12.50/boe) and higher realized hedging gains ($5.96/boe versus $4.18/boe).

General and Administrative Expenses

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Gross costs	**$2,292,956**	$2,193,236	5	**$4,597,204**	$4,663,757	(1)
Capitalized costs and recoveries	**(530,550)**	(540,550)	(2)	**(1,064,112)**	(938,380)	13
General and administrative costs	**$1,762,406**	$1,652,686	7	**$3,533,092**	$3,725,377	(5)
Total ($/boe)	**$2.03**	$2.60	(22)	**$2.03**	$2.73	(26)

General and administrative ("G&A") expenses for the second quarter of 2016 were $2.03/boe on costs of $1,762,406 compared to $2.03/boe on costs of $1,770,686 in the first quarter of 2016. During the second quarter of 2015, G&A expenses were $2.60/boe on costs of $1,652,686. Second quarter 2016 per boe G&A costs were 22% lower due to the impact of the 36% increase in production, partially offset by a 7% increase in absolute G&A costs.

For the first half of 2016, G&A expenses were $2.03/boe on costs of $3,533,092 compared to $2.73/boe on costs of $3,725,377 during the same period in 2015. The 26% decrease in the second half of 2016 cost per boe was due to the impact of a 27% increase in production and a 5% decrease in absolute G&A costs.

Stock-based Compensation Expenses

Stock-based compensation expenses of $910,369 and $1,861,952 relating to stock options and restricted share awards for the three and six months ended June 30, 2016, compared to $857,833 and $1,597,346 for the same periods in 2015. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $389,922 and $796,696 of stock-based compensation expenses relating to exploration and development activities for the three and six months ended June 30, 2016, compared to capitalizing $380,804 and $794,196 for the same periods in 2015.

Interest

Interest expense was $820,096 and $1,863,537 for the three and six months ended June 30, 2016, compared to $1,415,436 and $2,656,970 for the same periods in 2015. The Company had $48,629,824 drawn on its revolving credit facility at June 30, 2016, compared to $88,500,000 drawn on its bank line at June 30, 2015. Interest expense was lower for the three and six months ended June 30, 2016 compared to the same time periods in 2015 due to a lower average amount drawn quarter over quarter on the revolving credit facility. The average amount drawn for the three and six months ended June 30, 2016 was approximately $49 million and $62 million as compared to an average amount drawn of approximately $105 million and $106 million during the same periods in 2015.

Depletion, Depreciation, Amortization and Accretion

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

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Depletion and depreciation	**$14,923,784**	$13,336,610	12	**$30,074,278**	$29,263,822	3
Amortization of undeveloped leases	**188,319**	190,590	(1)	**354,037**	395,517	(10)
Accretion	**326,193**	183,922	77	**672,995**	441,022	53
Total	**$15,438,296**	$13,711,122	13	**$31,101,310**	$30,100,361	3
Depletion and depreciation ($/boe)	**$17.20**	$20.96	(18)	**$17.29**	$21.45	(19)
Amortization ($/boe)	**0.22**	0.30	(27)	**0.20**	0.29	(31)
Accretion ($/boe)	**0.38**	0.29	31	**0.39**	0.32	22
Total ($/boe)	**$17.80**	$21.55	(17)	**$17.88**	$22.06	(19)

Depletion, depreciation, amortization, and accretion (“DDA&A”) expense on a boe basis for the second quarter of 2016 was 1% lower at $17.80/boe, compared to $17.97/boe during the first quarter of 2016. For the second quarter of 2016, DDA&A expense was $15,438,296 compared to $15,663,014 for the first quarter of 2016.

Second quarter of 2016 DDA&A expense was $17.80/boe, compared to $21.55/boe for the same period in 2015, with the decrease due to a lower amortization rate, increased production related to lower-cost Cardium and heavy oil properties, and impairments to property, plant and equipment taken in the third quarter of 2015. On an absolute basis, DDA&A expense was 13% higher in the second quarter of 2016 at $15,438,296, compared to $13,711,122 in the second quarter of 2015 due to a 36% increase in production, partially offset by lower per unit DDA&A.

First half of 2016 DDA&A expense was $17.88/boe, compared to $22.06/boe for the same period in 2015, with the decrease due to a lower amortization rate, increased production related to lower-cost Cardium and heavy oil properties, and impairments to property, plant and equipment taken in the third quarter of 2015. On an absolute basis, DDA&A expense was 3% higher in the first half of 2016 at $31,101,310, compared to $30,100,361 in the first half of 2015, due to a 27% increase in production, partially offset by lower per unit DDA&A.

Income Taxes

The Company did not incur any cash tax expense in the three and six months ended June 30, 2016, nor does it expect to pay any cash taxes in 2016 or in 2017 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and six months ended June 30, 2016, a deferred income tax recovery of $3,498,508 and $5,304,532 was recognized, compared to a deferred income tax recovery of $3,634,876 and $5,135,581 for the same periods in 2015. There was a deferred tax recovery during the three and six months ended June 30, 2016 and 2015 due to the pre-tax losses recognized in these periods.

Funds from Operations and Net Income

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$24,516,988**	$25,330,543	(3)	**$44,135,647**	$50,641,176	(13)
Royalties	**(1,048,997)**	(2,192,889)	52	**(2,829,359)**	(4,949,053)	43
Realized gain (loss) on financial instruments	**4,070,977**	2,057,584	98	**10,375,979**	5,699,443	82
Production expenses	**(9,592,542)**	(7,909,969)	(21)	**(19,747,300)**	(17,049,286)	(16)
General and administration expenses	**(1,762,406)**	(1,652,686)	(7)	**(3,533,092)**	(3,725,377)	5
Transaction costs	**–**	(1,031,517)	100	**(96,254)**	(1,031,517)	91
Interest	**(820,096)**	(1,415,436)	42	**(1,863,537)**	(2,656,970)	30
Funds from operations	**$15,363,924**	$13,185,630	17	**$26,442,084**	$26,928,416	(2)

Funds from operations during the second quarter of 2016 were $15,363,924 ($0.13 per share basic and diluted) compared to $11,078,160 ($0.11 per share basic and diluted) for the first quarter of 2016. The increase is primarily the result of a 47% increase in crude oil and natural gas liquids pricing, a 6% decrease in production expenses and a 41% decrease in royalty expense, partially offset by a 20% decrease in natural gas prices and a lower realized hedging gain.

Compared to funds from operations of $13,185,630 ($0.16 per share basic and diluted) in the same period in 2015, second quarter 2016 funds from operations were 17% higher as a result of a 36% increase in production, a higher realized hedging gain in the second quarter of 2016 compared to the same period in

2015, no transaction costs in the second quarter of 2016 and a 52% decrease in royalty expense, partially offset by an 18% decrease in crude oil and natural gas liquids pricing, a 42% decrease in natural gas pricing and higher production expenses related to Tamarack's increased volumes.

Funds from operations during the first half of 2016 were $26,442,084 ($0.24 per share basic and diluted) compared to $26,928,416 ($0.33 per share basic and diluted) for the same period in 2015. The decrease is primarily the result of a 24% decrease in crude oil and natural gas liquids pricing, a 36% decrease in natural gas pricing and a 16% increase production expenses related to Tamarack's increased volumes, partially offset by a 27% increase in production, a higher realized hedging gain, a 91% decrease in transaction costs and a 43% decrease in royalty expense.

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$28.25**	$39.82	(29)	**$25.37**	$37.11	(32)
Royalties	**(1.21)**	(3.45)	65	**(1.63)**	(3.63)	55
Realized gain (loss) on financial instruments	**4.69**	3.23	45	**5.96**	4.18	43
Production expenses	**(11.05)**	(12.43)	11	**(11.35)**	(12.50)	9
General and administration expenses	**(2.03)**	(2.60)	22	**(2.03)**	(2.73)	26
Transaction costs	**–**	(1.62)	100	**(0.06)**	(0.76)	92
Interest	**(0.95)**	(2.22)	57	**(1.07)**	(1.95)	45
Funds from operations	**17.71**	20.73	(15)	**$15.20**	$19.74	(23)

Second quarter of 2016 funds from operations increased 39% to $17.71/boe from $12.71/boe in the first quarter of 2016 due to a 47% increase in crude oil and natural gas liquids prices, a 5% decrease in production expenses per boe and a 41% decrease in royalty expense per boe, partially offset by a 35% decrease in the realized hedging gain and a 20% decrease in natural gas prices.

Compared to funds from operations of $20.73/boe realized in the second quarter of 2015, funds from operations in the second quarter of 2016 were 15% lower due to an 18% decrease in crude oil and natural gas liquids prices and a 42% decrease in natural gas prices, partially offset by no transactions costs in the second quarter of 2016, an 11% decrease in production expenses per boe, a 22% decrease in G&A expense per boe, a 65% decrease in royalty expense per boe and a 45% increase in the realized hedging gain.

First half of 2016 funds from operations decreased 23% to $15.20/boe from $19.74/boe in the first half of 2015 due to a 24% decrease in crude oil and natural gas liquids prices and a 36% decrease in natural gas prices, partially offset by a 92% decrease in transaction costs, a 9% decrease in production expenses per boe, a 26% decrease in G&A expense per boe, a 55% decrease in royalty expense per boe and a 43% increase in the realized hedging gain.

The Company had a net loss of $10,369,299 ($0.09 per share basic and diluted) during the three months ended June 30, 2016, compared to a net loss of $5,834,537 ($0.06 per share basic and diluted) for the first quarter of 2016 due primarily to the $12,883,066 unrealized loss on financial instruments in the second quarter of 2016 compared to the unrealized loss of $2,104,124 in the first quarter of 2016. Other contributing factors to the higher net loss for the three months ended June 30, 2016 as compared to the previous quarter was a lower realized gain on financial instruments and a 20% decrease in natural gas pricing, partially offset by a 47% increase in crude oil and natural gas liquids pricing.

The Company had a net loss of $10,369,299 ($0.09 per share basic and diluted) during the three months ended June 30, 2016, compared to a net loss of $2,141,787 ($0.03 per share basic and diluted) for the same period in 2015. This was a result of several factors, including a higher unrealized loss on financial instruments, an 18% decrease in crude oil and natural gas liquids pricing, a 42% decrease in natural gas pricing and higher production expenses related to increased production, partially offset by higher realized hedging gains in the second quarter of 2016 compared to the second quarter of 2015 and by transaction costs being incurred in the second quarter of 2015.

The Company had a net loss of $16,203,836 ($0.15 per share basic and diluted) during the six months ended June 30, 2016, compared to a net loss of $7,383,417 ($0.09 per share basic and diluted) for the same period in 2015. This was a result of several factors, including a higher unrealized loss on financial instruments, a 24% decrease in crude oil and natural gas liquids pricing, a 36% decrease in natural gas pricing and higher production expenses related to increased production, partially offset by higher realized hedging gains, lower transaction costs and a 27% 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 June 30,			Six months ended June 30,		
	2016	2015	% change	**2016**	2015	% change
Land	**568,895**	$335,922	69	**1,178,132**	$411,544	186
Geological and geophysical	**1,234**	(22,997)	105	**412,873**	7,509	5,398
Drilling and completion	**6,574,106**	8,205,965	(20)	**20,820,005**	12,814,694	62
Equipment and facilities	**2,733,594**	5,543,683	(51)	**4,266,146**	7,510,352	(43)
Capitalized G&A	**290,695**	317,181	(8)	**526,209**	484,412	9
Office equipment	**140,985**	1,485	9,394	**255,482**	1,485	17,104
Total capital expenditures	**$10,309,509**	$14,381,239	(28)	**$27,458,847**	$21,229,996	29
Property acquisition	**–**	54,173,650	(100)	**–**	54,173,650	(100)
Proceeds from disposal of property, plant and equipment	**–**	(135,000)	(100)	**–**	(1,955,583)	(100)
Total net capital expenditures	**$10,309,509**	$68,419,889	(85)	**$27,458,847**	$73,448,063	(63)

During the second quarter of 2016, the Company drilled, completed and equipped 2 (2.0 net) 2-mile Cardium oil wells and 1 (1.0 net) Heavy oil well. The Company also completed the installation of a field compressor diverting Company production away from third party facilities into owned and operated facilities in order to reduce operating costs.

2016 Drilling Summary (including wells spudded by June 30, 2016)		
	Gross	Net
Heavy Oil	2.0	2.0
Mannville	1.0	0.8
Cardium	5.0	4.5
	8.0	7.3

The Company has also been focused on adding drilling inventory through minor tuck-in land acquisitions in its core areas. During the second quarter, three minor deals were completed, adding approximately 6 net sections of undeveloped land, as well as 14.5 net sections of undeveloped lands through land sale activity.

The Company's net undeveloped land was 223,197 acres at the end of the second quarter of 2016.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $57,791,039 at June 30, 2016. Tamarack's net debt at June 30, 2015 was $97,280,149 and at December 31, 2015 was $97,940,880. During the six months ended June 30, 2016 the Company reduced net debt by $40,149,841 through an equity issuance described below, which improved financial flexibility. Tamarack's June 30, 2016 net debt to annualized funds from operations was 0.9 times as compared to year end December 31, 2015 at 1.3 times.

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

Subsequent to June 30, 2016, the Company completed a bought deal financing on July 12, 2016 in concert with the Penny / Redwater Acquisition, resulting in the issuance of 20,110,050 common shares at $3.66 per share for total gross proceeds of $73,602,783. This included an over-allotment option being exercised for 2,623,050 common shares. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817.

Subsequent to June 30, 2016, the Company also issued 1,952,000 flow-through common shares related to Canadian development expenditures at $4.10 per share for total gross proceeds of $8,003,200. Certain officers and directors acquired 4,900 flow-through common shares for gross proceeds of $20,090.

During the six months ended June 30, 2016, 16,000 stock options at $2.06 per share were exercised for total gross proceeds of $32,960.

At June 30, 2016 there were 114,953,425 common shares, 4,652,884 options and 1,861,167 restricted share awards outstanding. At August 10, 2016 there were 137,015,475 common shares, 4,652,884 options and 1,861,167 restricted share awards outstanding. This compares to December 31, 2015 at which time there were 99,971,325 common shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. The Company had 114,945,337 and 108,609,570 weighted average basic common shares outstanding during the three and six months ended June 30, 2016. No preferred shares of the Company are issued and outstanding.

At December 31, 2015 and June 30, 2016, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 commons shares of the Company. The preferred shares of Tamarack Acquisition Corp. are fully vested at June 30, 2016 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share. An exchange of the preferred shares is at the election of the Company under certain circumstances.

The Company currently has available a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $120 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018 (the "Maturity Date"). The Facility was originally scheduled for review and renewal on May 27, 2016 and through agreement between the Company and the syndicate was extended and completed on July 8, 2016. Although the renewal date was extended, the prior Maturity Date of May 27, 2017 remained in effect throughout the period of extension which encompassed the June 30, 2016 statement of financial position date. As such, amounts outstanding of $48.6 million at period end have been shown as a current liability. Prior to the renewal, the revolving credit facility was $155 million. The previous borrowing base was reduced to reflect an appropriate amount of liquidity for the Company given the current commodity price environment and to save on standby and renewal fees.

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 review is scheduled to take place on November 30, 2016.

Pursuant to the terms of the Facility, the Company has provided a covenant that at all times its adjusted working capital ratio shall not be less than 1.0 to 1.0 which shall be calculated on a quarterly basis. The adjusted working capital ratio is defined under the terms of the credit facilities as current assets, excluding derivative assets and including the undrawn portion of the Facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities. The Company is in compliance 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 balance sheet strength by adjusting capital spending relative to changes in commodity prices. The Company intends to maintain balance sheet flexibility in order to be opportunistic and take advantage of potential tuck-in acquisitions within its core areas while commodity prices are low. The equity issuance completed on March 18, 2016, and the Penny / Redwater Acquisition and related equity issuance on July 12, 2016 were consistent with that strategy. Tamarack will focus on drilling wells that target a return on capital cost payout of 1.5 years or less. The Company will also continue to focus on reducing capital and operating costs in order to optimize capital efficiencies.

2016 Guidance

Tamarack’s 2016 capital program and associated guidance was designed with the key priority of maintaining a strong and flexible balance sheet. The capital program and initial guidance released on January 19, 2016, was based on a 2016 WTI average of $40.00/bbl USD and an AECO average of $2.45/GJ with a plan to adjust capital spending as commodity prices changed. Despite having a high-quality drilling inventory that achieves 1.5 year payouts or less in the current pricing environment, the Company adjusted capital spending as a result of the continued volatility in commodity prices. As commodity prices decreased during the first quarter of 2016, the Company deferred approximately $6 to $8 million of capital into the second half of 2016.

The top priority is to maintain a strong balance sheet in order to continue its successful pursuit of tuck-in acquisitions within its core areas and to continue adding high quality drilling inventory. Tamarack will continue to closely monitor the broader commodity price environment and has the flexibility to accelerate or reduce capital expenditures in accordance with commodity price fluctuations from current levels.

In conjunction with the Penny / Redwater Acquisition, Tamarack updated its guidance on July 12, 2016 as follows:

2016 Assumptions:

- WTI average $44.00/bbl to 47.00/bbl USD.
- Edmonton par price average $52.00/bbl to 56.00/bbl.
- AECO average $1.80/GJ to 2.00/GJ.
- Canadian/US dollar exchange rate range of $0.77 to $0.78.

2016 Guidance Ranges:

- Capital expenditures of $45-53 million.
- Average production of 9,700-10,000 boe/d (approximately 53-57% oil & NGLs).
- Exit production of 11,000 boe/d (approximately 53-57% oil & NGLs).
- Estimated 2016 year end 12-month trailing debt to cash flow (including hedges) ratio of less than 0.8 times.

Commitments

The following table summarizes the Company's commitments at June 30, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	316,858	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments[(1)]	494,100	985,500	985,500	–	–	–	–	–
Drilling commitments[(2)]	2,609,000	–	–	–	–	–	–	–
Rental fee[(3)]	2,585,063	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	6,005,021	6,796,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 31 months.

(2) Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 net wells needed to be drilled by December 31, 2016. In the event the Company gets access to certain lands that are currently restricted from access due to regulatory conditions, the number of wells would then increase to 20 and the Company would have until December 31, 2017 to fulfill this commitment. As of June 30, 2016, the Company had satisfied approximately 93% of the drilling commitment (70% if increased to 20 wells) and estimates the capital expenditures to fulfill the remainder of this commitment will be approximately $3 million ($15 million if increased to 20 wells).

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

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Regulators National Instrument 51–101 *Standards of Disclosure for Oil and Gas Activities*. Boe may be misleading, particularly if used in isolation.

Abbreviations

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

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

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 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
Cash provided by operating activities	**$14,560,060**	$9,329,867	**$29,042,863**	$26,201,073
Abandonment expenditures	**30,220**	88,253	**183,417**	154,807
Changes in non-cash working capital	**773,644**	3,767,510	**(2,784,196)**	572,536
Funds from operations	**$15,363,924**	$13,185,630	**$26,442,084**	$26,928,416
Funds from operation per share - basic	**$ 0.13**	$ 0.16	**$ 0.24**	$ 0.33
Funds from operation per share - diluted	**$ 0.13**	$ 0.16	**$ 0.24**	$ 0.33

(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 7 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):

	June 30, 2016	December 31, 2015
Cash and cash equivalents	$ –	$ –
Accounts receivables	13,844,821	15,571,507
Prepaid expenses	979,746	1,039,634
Accounts payable and accrued liabilities	(23,985,782)	(31,730,161)
Bank debt	(48,629,824)	(82,821,860)
Net debt	$(57,791,039)	$(97,940,880)

Selected Quarterly Information

Three months ended	**Jun. 30, 2016**	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014
Sales volumes								
Natural gas *(mcf/d)*	**27,462**	25,818	23,229	22,005	16,972	17,864	17,518	12,462
Oil and NGL's *(bbls/d)*	**4,959**	5,279	6,096	5,049	4,163	5,115	4,761	3,688
Average boe/d *(6:1)*	**9,536**	9,582	9,968	8,717	6,992	8,092	7,681	5,765
Product prices								
Natural gas *($/mcf)*	**1.62**	2.03	2.66	3.04	2.80	2.91	3.91	4.13
Oil and NGL's *($/bbl)*	**45.35**	30.90	39.30	46.56	55.47	48.33	62.87	90.19
Oil equivalent *($/boe)*	**28.25**	22.50	30.23	34.64	39.82	34.75	47.89	66.62
(000s, except per share amounts)								
Financial results								
Gross revenues	**24,517**	19,619	27,725	27,779	25,331	25,311	33,839	35,333
Funds from operations	**15,364**	11,078	18,615	14,618	13,186	13,743	19,128	15,809
Per share – basic	**0.13**	0.11	0.19	0.15	0.16	0.18	0.25	0.26
Per share – diluted	**0.13**	0.11	0.18	0.15	0.16	0.18	0.25	0.26
Net income (loss)	**(10,369)**	(5,835)	5,119	(15,064)	(2,142)	(5,242)	(38,991)	6,791
Per share – basic	**(0.09)**	(0.06)	0.05	(0.15)	(0.03)	(0.07)	(0.50)	0.11
Per share – diluted	**(0.09)**	(0.06)	0.05	(0.15)	(0.03)	(0.07)	(0.50)	0.11
Additions to property and equipment, net of proceeds	**10,310**	17,149	8,743	21,936	14,246	5,028	26,774	30,318
Net property acquisitions	**–**	–	2,075	1,230	54,174	–	–	166,057
Total assets	**542,917**	553,135	549,068	549,652	561,977	482,227	497,578	525,003
Net debt[1]	**(57,791)**	(62,696)	(97,941)	(105,837)	(97,280)	(121,159)	(129,799)	(121,684)
Bank debt	**48,630**	50,056	82,822	94,423	88,500	112,951	100,200	100,275
Decommissioning obligations	**68,149**	65,643	63,331	61,808	64,883	45,340	41,357	36,732
Deferred income tax (asset)	**(42,116)**	(38,576)	(36,168)	(35,770)	(33,647)	(28,802)	(27,299)	(16,870)

(1) Refer to definition of net debt under "Non IFRS Measures"

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

- The volatility in commodity prices and the resultant effect on revenue and net income (loss).
- The volatility in forward price curves which affects the mark-to-market calculation, and 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, 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta (the "Wilson Creek / Alder Flats Acquisition"); in 2015 this acquisition added $7,266,186 to oil and natural gas revenue and contributed $1,045,845 to net loss.
- On September 30, 2014, the Company acquired 100% of the interests owned by a major oil and

gas producer in the Wilson Creek area of Alberta (the "Wilson Creek Acquisition"); in 2014 this acquisition added $5,551,131 to oil and natural gas revenue and contributed $402,656 to net income.

- The Company recorded $1,044,308 in transaction costs in the second and third quarters of 2015 related to the Wilson Creek / Alder Flats Acquisition and $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek 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 Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

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

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

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

Exploration and evaluation expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

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

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

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

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

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

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures (“DCP”) to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Business Risks

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

Financial Risks

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

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

Operational Risks

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

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

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

Forward Looking Statements

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

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

- Estimated production rates in 2016.
- Future operating costs.
- Reduction of production expenses on an absolute and per boe basis in the second quarter of 2016.
- Tamarack's focus on reducing capital and operating costs.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- The timing of review of the Facility.
- Future capital expenditures and capital program funding.
- The Company's capital program and guidance for 2016.

- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas pricing in 2016.
- Expectations as to oil and natural gas weighting in 2016.
- Expectations as to royalty rates in 2016 and the implementation of the MRF by the Government of Alberta.
- The ability of the Company to take advantage of opportunities that may arise while commodity prices are low.

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

- future commodity prices;
- expected operating costs;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties;
- 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 Annual Information Form for the year ended December 31, 2015, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets

(unaudited)

	June 30, 2016	December 31, 2015
Assets		
Current assets:		
Accounts receivable	$13,844,821	$15,571,507
Prepaid expenses and deposits	979,746	1,039,634
Fair value of financial instruments (note 3)	–	12,468,101
	14,824,567	29,079,242
Property, plant and equipment (note 4)	483,006,857	481,615,900
Exploration and evaluation assets (note 5)	2,969,391	2,204,978
Deferred tax asset	42,115,793	36,167,594
	$542,916,608	$549,067,714
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$23,985,782	$31,730,161
Fair value of financial instruments (note 3)	2,519,089	–
Bank debt (note 10)	48,629,824	–
	75,134,695	31,730,161
Bank debt (note 10)	–	82,821,860
Decommissioning obligations (note 6)	68,148,570	63,330,850
Shareholders' equity:		
Share capital (note 8)	458,090,157	416,075,358
Contributed surplus	19,681,941	17,044,404
Deficit	(78,138,755)	(61,934,919)
	399,633,343	371,184,843
Commitments and contingencies (note 12)		
Subsequent events (note 13)		
	$542,916,068	$549,067,714

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Loss and Comprehensive Loss
For the three and six months ended June 30, 2016 and 2015
(unaudited)

	Three Months ended June 30,		Six Months ended June 30,	
	2016	2015	2016	2015
Revenue:				
Oil and natural gas	$24,516,988	$25,330,543	$44,135,647	$50,641,176
Royalties	(1,048,997)	(2,192,889)	(2,829,359)	(4,949,053)
Realized gain on financial instruments (note 3)	4,070,977	2,057,584	10,375,979	5,699,443
Unrealized loss on financial instruments (note 3)	(12,883,066)	(4,528,338)	(14,987,190)	(7,337,619)
	14,655,902	20,666,900	36,695,077	44,053,947
Expenses:				
Production	9,592,542	7,909,969	19,747,300	17,049,286
General and administration	1,762,406	1,652,686	3,533,092	3,725,377
Transaction costs	–	1,031,517	96,254	1,031,517
Stock-based compensation (note 11)	910,369	857,833	1,861,952	1,597,346
Finance	1,146,289	1,599,358	2,536,532	3,097,992
Depletion, depreciation and amortization	15,112,103	13,527,200	30,428,315	29,659,339
Loss (gain) on disposition of property, plant and equipment	–	(135,000)	–	412,088
	28,523,709	26,443,563	58,203,445	56,572,945
Loss before taxes	(13,867,807)	(5,776,663)	(21,508,368)	(12,518,998)
Deferred income tax recovery	3,498,508	3,634,876	5,304,532	5,135,581
Net loss and comprehensive loss	$(10,369,299)	$(2,141,787)	$(16,203,836)	$(7,383,417)
Net loss per share (note 9):				
Basic	$(0.09)	$(0.03)	$(0.15)	$(0.09)
Diluted	$(0.09)	$(0.03)	$(0.15)	$(0.09)

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, 2016	99,971,325	$416,075,358	$17,044,404	$(61,934,919)	$371,184,843
Issue of common shares	14,982,100	43,733,972	–	–	43,733,972
Share issue costs, net of tax of $643,667	–	(1,740,284)	–	–	(1,740,284)
Transfer on exercise of stock options	–	21,111	(21,111)	–	–
Stock-based compensation	–	–	2,658,648	–	2,658,648
Net loss	–	–	–	(16,203,836)	(16,203,836)
Balance at June 30, 2016	114,953,425	$458,090,157	$19,681,941	$(78,138,755)	$399,633,343

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2015	77,928,466	$336,086,662	$12,931,358	$(44,606,551)	$304,411,469
Issue of common shares	19,818,459	74,860,360	–	–	74,860,360
Issue of flow-through shares	2,186,800	9,075,220	–	–	9,075,220
Share issue costs, net of tax of $1,212,711	–	(3,529,891)	–	–	(3,529,891)
Transfer on exercise of stock options and preferred shares	–	247,906	(247,906)	–	–
Flow-through share premium	–	(809,116)	–	–	(809,116)
Stock-based compensation	–	–	2,391,542	–	2,391,542
Net loss	–	–	–	(7,383,417)	(7,383,417)
Balance at June 30, 2015	99,933,725	$415,931,141	$15,074,994	$(51,989,968)	$379,016,167

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 six months ended June 30, 2016 and 2015
(unaudited)

	Three Months ended June 30,		Six Months ended June 30,	
	2016	2015	2016	2015
Cash provided by (used in):				
Operating:				
Net loss	$(10,369,299)	$(2,141,787)	$(16,203,836)	$(7,383,417)
Items not involving cash:				
Depletion, depreciation and amortization	15,112,103	13,527,200	30,428,315	29,659,339
Stock-based compensation	910,369	857,833	1,861,952	1,597,346
Loss (gain) on disposition of property, plant and equipment	–	(135,000)	–	412,088
Accretion expense on decommissioning obligations	326,193	183,922	672,995	441,022
Unrealized gain on financial instruments	12,883,066	4,528,338	14,987,190	7,337,619
Deferred income tax recovery	(3,498,508)	(3,634,876)	(5,304,532)	(5,135,581)
Funds from operations	15,363,924	13,185,630	26,442,084	26,928,416
Abandonment expenditures (note 6)	(30,220)	(88,253)	(183,417)	(154,807)
Changes in non-cash working capital (note 7)	(773,644)	(3,767,510)	2,784,196	(572,536)
Cash provided by operating activities	14,560,060	9,329,867	29,042,863	26,201,073
Financing:				
Change in bank debt	(1,426,096)	(24,451,205)	(34,192,036)	(11,700,000)
Proceeds from issuance of shares	32,960	83,935,580	43,733,972	83,935,580
Share issue costs	(151,738)	(4,734,202)	(2,383,951)	(4,742,602)
Cash provided by (used in) financing activities	(1,544,874)	54,750,173	7,157,985	67,492,978
Investing:				
Property, plant and equipment additions	(9,699,113)	(13,880,319)	(25,741,132)	(20,358,009)
Exploration and evaluation additions	(610,396)	(500,920)	(1,717,715)	(871,987)
Acquisitions	–	(54,983,084)	–	(54,983,084)
Proceeds from disposal of property, plant and equipment	–	135,000	–	1,955,583
Changes in non-cash working capital (note 7)	(2,705,677)	8,577,725	(8,742,001)	(16,838,216)
Cash used in investing activities	(13,015,186)	(60,651,598)	(36,200,848)	(91,095,713)
Change in cash and cash equivalents	–	3,428,442	–	2,598,338
Cash and cash equivalents, beginning of period	–	–	–	830,104
Cash and cash equivalents, end of period	$ –	$3,428,442	$ –	$3,428,442

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The condensed consolidated interim financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. On January 1, 2016, Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp., completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp". 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 Suite 600, 425 – 1st Street S.W., Calgary, Alberta T2P 3L8.

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 Financial 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, 2015. 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, 2015.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on August 10, 2016.

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 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 June 30, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	1,800 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $69.92	$1,055,054
Crude oil	2,000 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.43	$165,897
Crude oil	1,700 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $59.15	($1,153,926)
Crude oil	1,700 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $60.24	($1,104,745)
Crude oil	800 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $63.73	($309,201)
Natural gas	3,000 GJ/day	July 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53	$214,104
Natural gas	9,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.31	($339,153)
Natural gas	10,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.64	($396,281)
Natural gas	12,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.37	($293,986)
Natural gas	12,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.41	($242,801)
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79	($114,051)
					($2,519,089)

At June 30, 2016, the commodity contracts were fair valued with a liability of $2,519,089 (December 31, 2015 - $12,468,101 asset) recorded on the balance sheet and an unrealized loss of $14,987,190 recorded in earnings.

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 June 30, 2016, the Company held physical commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	July 1, 2016 – September 30, 2016	AECO fixed price	Cdn $2.44
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

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

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

Gross Amounts	**June 30, 2016**	December 31, 2015
Risk management contracts		
Current asset	**$1,435,055**	$12,468,101
Current liability	**($3,954,144)**	–
Balance, end of the period	**($2,519,089)**	$12,468,101

4. Property, plant and equipment:

	Oil and Natural Gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2015	$585,493,847	$332,484	$585,826,331
Property acquisition	66,716,576	–	66,716,576
Cash additions	61,490,520	268,747	61,759,267
Decommissioning costs	12,207,496	–	12,207,496
Stock-based compensation	1,419,207	–	1,419,207
Transfer from exploration and evaluation assets	1,989,039	–	1,989,039
Disposals	(12,928,641)	–	(12,928,641)
Balance at December 31, 2015	716,388,044	601,231	716,989,275
Cash additions	25,485,650	255,482	25,741,132
Decommissioning costs	4,328,142	–	4,328,142
Stock-based compensation	796,696	–	796,696
Transfer from exploration and evaluation assets	599,265	–	599,265
Balance at June 30, 2016	$747,597,797	$856,713	$748,454,510
Depletion, depreciation and impairment losses:			
Balance at January 1, 2015	$150,320,639	$177,576	$150,498,215
Depletion and depreciation	58,744,439	87,101	58,831,540
Disposals	(131,380)	–	(131,380)
Impairment loss	26,175,000	–	26,175,000
Balance at December 31, 2015	235,108,698	264,677	235,373,375
Depletion and depreciation	30,006,587	67,691	30,074,278
Balance at June 30, 2016	$265,115,285	$332,368	$265,447,653

	Oil and Natural Gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2015	$481,279,346	$336,554	$481,615,900
At June 30, 2016	$482,482,512	$524,345	$483,006,857

The calculation of depletion at June 30, 2016 includes estimated future development costs of $356,557,000 (December 31, 2015 – $361,667,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $26,449,000 (December 31, 2015 – $25,630,400).

5. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2015	$23,631,049
Additions	440,838
Transfer to property, plant and equipment	(1,989,039)
Balance at December 31, 2015	22,082,848
Additions	1,717,715
Transfer to property, plant and equipment	(599,265)
Balance at June 30, 2016	$23,201,298
Amortization and impairment:	
Balance at January 1, 2015	$19,162,226
Amortization	715,644
Balance at December 31, 2015	19,877,870
Amortization	354,037
Balance at June 30, 2016	$ 20,231,907

	Total
Carrying amounts:	
At December 31, 2015	$2,204,978
At June 30, 2016	$2,969,391

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.

6. 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 $63.7 million at June 30, 2016 (December 31, 2015 – $63.0 million), which is expected to be incurred between 2016 and 2038. A risk-free rate of 1.80% (2015 – 2.2%) and an inflation rate of 2% (2015 – 2%) is used to calculate the fair value of the decommissioning obligations at June 30, 2016 as presented in the table below:

	June 30, 2016	December 31, 2015
Balance, beginning of the period	**$63,330,850**	$41,356,532
Liabilities incurred	**675,468**	1,091,390
Liabilities acquired	–	9,237,544
Change in estimates	**3,652,674**	444,130
Change in discount rate on acquisition	–	10,671,976
Expenditures	**(183,417)**	(155,559)
Liabilities disposed	–	(369,117)
Accretion	**672,995**	1,053,954
Balance, end of the period	**$68,148,570**	$63,330,850

A change in estimates for 2016 resulted from the decommissioning obligations being revalued using the risk-free rate of 1.8% as opposed to the risk free rate of 2.2% used in 2015.

7. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
Source/(use of cash):				
Accounts receivable	**$1,097,195**	$(968,445)	**$1,726,686**	$4,632,523
Prepaid expenses and deposits	**94,168**	(181,162)	**$59,888**	(11,366)
Accounts payable and accrued liabilities	**(4,670,684)**	5,150,388	**(7,744,379)**	(22,841,343)
Working capital acquired on acquisition	**–**	809,434	**–**	809,434
	$(3,479,321)	$4,810,215	**$(5,957,805)**	$(17,410,752)
Related to operating activities	**$(773,644)**	$(3,767,510)	**$2,784,196**	$(572,536)
Related to investing activities	**(2,705,677)**	8,577,725	**$(8,742,001)**	$(16,838,216)

8. Share capital:

At June 30, 2016 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

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

During the six months ended June 30, 2016 16,000 stock options at $2.06 per share were exercised for gross proceeds of $32,960.

9. Income (loss) per share:

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
Net loss	**$(10,369,299)**	$(2,141,787)	**$(16,203,836)**	$(7,383,417)
Weighted average shares - basic	**114,945,337**	84,493,217	**108,609,570**	81,228,976
Weighted average shares - diluted	**114,945,337**	84,493,217	**108,609,570**	81,228,976
Net loss per share-basic	**$(0.09)**	$(0.03)	**$(0.15)**	$(0.09)
Net loss per share-diluted	**$(0.09)**	$(0.03)	**$(0.15)**	$(0.09)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and six months ended June 30, 2016, 7,624,635 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 six months ended June 30, 2015, 5,582,635 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive.

10. Bank debt:

The Company currently has available a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility totaling $120 million lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018 (the “Maturity Date”). The Facility was originally scheduled for review and renewal on May 27, 2016 and through agreement between the Company and the syndicate was extended and completed on July 8, 2016. Although the renewal date was extended, the prior Maturity Date of May 27, 2017 remained in effect throughout the period of extension which encompassed the June 30, 2016 statement of financial position date. As such, amounts outstanding of $48.6 million at period end have been shown as a current liability. Prior to the renewal, the revolving credit facility was $155 million.

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 review is scheduled to take place on November 30, 2016.

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 June 30, 2016, the Company had utilized the Facility in the amount of $48.6 million and the Company was compliant with its working capital ratio at 5.6 to 1.0. As at June 30, 2016, the Company had letter of guarantees outstanding in the amount of $43,980 against the Facility.

11. Share-based payments:

(a) Preferred share plan:

There are 1,155,007 preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1,110,584 common shares of the Company (December 31, 2015 – 1,110,584). The preferred shares of Tamarack Acquisition Corp. are fully vested at June 30, 2016 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share. An exchange of the preferred shares is at the election of the Company under certain circumstances.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 11,495,343 options or restricted share units to its employees, directors and consultants of which 7,106,781 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 the date of grant. There were no options granted during the period.

The number and weighted average exercise prices of stock options under the plan are as follows:

	Number of options	Weighted average exercise price
Outstanding, January 1, 2015	4,147,386	$ 3.70
Granted	727,000	2.84
Exercised	(29,167)	3.60
Forfeited	(134,668)	2.94
Expired	(41,667)	4.44
Outstanding, December 31, 2015	4,668,884	$ 3.59
Exercised	(16,000)	2.06
Outstanding, June 30, 2016	4,652,884	$ 3.59

The following table summarizes information about stock options outstanding and exercisable at June 30, 2016:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price
$ 1.86 – 3.00	1,737,051	$2.35	2.5	1,067,051	$2.12
$ 3.01 – 5.00	2,449,833	$3.85	2.3	1,640,499	$3.85
$ 5.01 – 6.82	466,000	$6.82	3.1	155,333	$6.82
$ 1.86 – 6.82	**4,652,884**	**$3.59**	**2.4**	**2,862,883**	**$3.37**

(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 restricted 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.

The following table summarizes information about the restricted share awards:

	Number of awards
Outstanding, January 1, 2015	406,500
Granted	1,459,000
Exercised	(4,333)
Outstanding, December 31, 2015 and June 30, 2016	1,861,167

12. Commitments and contingencies:

(a) Commitments

The following table summarizes the Company's commitments at June 30, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	316,858	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments[1]	494,100	985,500	985,500	–	–	–	–	–
Drilling commitments[2]	2,609,000	–	–	–	–	–	–	–
Rental fee[3]	2,585,063	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	6,005,021	6,796,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 31 months.

(2) Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 net wells needed to be drilled by December 31, 2016. In the event the Company gets access to certain lands, that are currently restricted from access due to regulatory conditions, the number of wells would then increase to 20 and the Company would have until December 31, 2017 to fulfill this commitment. As of June 30, 2016, the Company had satisfied approximately 93% of the drilling commitment (70% if increased to 20 wells) and estimates the capital expenditures to fulfill the remainder of this commitment will be approximately $3 million ($15 million if increased to 20 wells).

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

(b) Contingencies

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

13. Subsequent events:

On July 12, 2016, the Company completed a bought deal financing by issuing 20,110,050 common shares at a price of $3.66 per share, for gross proceeds of $73,602,783 and 1,952,000 flow-through common shares, related to Canadian development expenditures, at $4.10 per share for gross proceeds of $8,003,200. The Company has until December 31, 2016 to incur the required expenditures at which time they will also be renounced to shareholders. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817 and 4,900 flow-through common shares for gross proceeds of $20,090.

On July 12, 2016, the Company acquired certain working interest in developed petroleum and natural gas properties in the Penny area of Southern Alberta for an aggregate cash purchase price of approximately $59.2 million after closing adjustments.

On July 25, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Redwater and Wilson Creek areas of Alberta for an aggregate cash purchase price of approximately $25.8 million after closing adjustments.

CORPORATE INFORMATION

Directors

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

Dean Setoguchi(1)(3)

David Mackenzie(1)(2)

Jeff Boyce(2)(3)

Noralee Bradley(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

Rummy Basra
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

Contact Information

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