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, 2017 and 2016. This MD&A is dated and based on information available on August 10, 2017 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, 2017 and 2016. 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 calculat15ion, please refer to the section titled "Non-IFRS and Additional IFRS Measures" beginning on page 15. 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 and Saskatchewan that are economic over a range of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its balance sheet.

Transformative Business Combination Expands Viking Oil Assets

On January 11, 2017, Tamarack closed the previously announced arrangement agreement (the "Arrangement Agreement") providing for the acquisition by Tamarack of all of the issued and outstanding common shares of Spur Resources Ltd. ("Spur"), which held Spur's Viking oil assets at closing (the "Viking Acquisition"). Under the terms of the Arrangement Agreement, the Company issued an aggregate of 90.1 million common shares of Tamarack and paid $57.8 million in cash. Tamarack also assumed Spur's net debt, estimated to be $23.7 million as at January 11, 2017, after accounting for proceeds from the exercise of all outstanding options of Spur, including severance and transaction costs. Based upon Tamarack's share price on January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $391 million.

Production

	Three months ended June 30,			Six months ended June 30,		
	2017	2016	% change	**2017**	2016	% change
Production						
Light oil (bbls/d)	**9,481**	3,656	159	**8,691**	3,729	133
Heavy oil (bbls/d)	**453**	384	18	**469**	397	18
Natural gas liquids (bbls/d)	**1,453**	919	58	**1,615**	993	63
Natural gas (mcf/d)	**47,696**	27,462	74	**46,779**	26,640	76
Total (boe/d)	**19,336**	9,536	103	**18,572**	9,559	94
Percentage of oil and natural gas liquids	**59%**	52%		**58%**	54%	

Average production for the second quarter of 2017 increased by 9% to 19,336 boe/d from 17,796 boe/d in the first quarter of 2017. Second quarter 2017 volumes were positively impacted by a full quarter of production related to the first quarter drilling program which contributed an additional 2,361 boe/d from Wilson Creek/Alder Flats (68% oil and natural gas liquids), 2,044 boe/d from the Viking development program (72% oil and natural gas liquids) and 394 boe/d from the heavy oil development program. These gains were partially offset by expected declines from legacy Tamarack volumes and 1,070 boe/d related to the unexpected shut-in of the TransGas Coleville Gas Plant (the "Coleville Plant"). The Coleville Plant commenced partial operations in the middle of July, with full-scale operations expected later in the year. Tamarack continues to have production of approximately 2.0 MMcf/d and 30 bbls/d of NGLs curtailed.

The Company's oil weighting increased 9% in the second quarter of 2017, averaging 51% compared to 47% in the first quarter of 2017 due to the higher oil-weighted drilling program in the Wilson Creek and Veteran areas of Alberta. For the remainder of 2017, the Company expects its oil weighting to remain in the 50-53% range with the combined oil and natural gas liquids weighting expected to fluctuate between 55% and 62%. This weighting is dependent on the timing of production additions from its higher oil-weighted areas of Wilson Creek, Penny and the Viking Acquisition assets, and additions from its higher natural gas-weighted area of Alder Flats. Oil and natural gas weightings may also be affected by production additions associated with future drilling of liquids-rich Mannville gas wells in the Wilson Creek area.

Crude oil and natural gas liquids production in the second quarter of 2017 continued to increase averaging 11,387 bbls/d, an increase of 12% compared to 10,154 bbls/d in the first quarter of 2017. The increase in oil and liquids production was due to the first quarter drilling program which contributed an additional 1,476 bbls/d from Wilson Creek/Alder Flats, 1,473 bbls/d from the Viking development program and 391 bbls/d from the heavy oil development program. These gains were partially offset by expected declines from legacy Tamarack volumes and 196 bbls/d related to the shut-in of the Coleville Plant. Tamarack's oil and natural gas liquids volumes represented 59% of total production in the second quarter of 2017 compared to 57% in the first quarter of 2017 and 52% in the second quarter of 2016.

Natural gas production averaged 47,696 mcf/d in the second quarter of 2017, an increase of 4% over the 45,852 mcf/d produced in the prior quarter. The production increase was due to the first quarter drilling program which contributed an additional 5,309 mcf/d from Wilson Creek/Alder Flats and 3,435 mcf/d from the Viking development program, partially offset by expected declines from legacy Tamarack volumes and 5,244 mcf/d related to the shut-in of the Coleville Plant.

Compared to the prior year, average second quarter 2017 production increased by 103% to 19,336 boe/d from 9,536 boe/d during the same period in 2016 and average production for the six months ended June 30, 2017 increased by 94% to 18,572 boe/d from 9,559 boe/d during the same period in 2016. These increases are attributable to the successful drilling programs in 2016 and 2017, as well as the impact of production from assets acquired in the Viking, Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended June 30,			Six months ended June 30,		
	2017	2016	% change	**2017**	2016	% change
Revenue ($ thousands)						
Oil and NGLs	**$53,649**	$20,460	162	**$104,591**	$35,304	196
Natural gas	**13,066**	4,057	222	**24,994**	8,832	183
Total	**$66,715**	$24,517	172	**$129,585**	$44,136	194
Average realized price						
Light oil ($/bbl)	**55.58**	52.16	7	**58.94**	44.34	33
Heavy oil ($/bbl)	**43.80**	37.31	17	**44.23**	30.09	47
Natural gas liquids ($/bbl)	**29.39**	21.57	36	**27.79**	16.81	65
Combined average oil and NGLs ($/boe)	**51.77**	45.35	14	**53.63**	37.90	42
Natural gas ($/mcf)	**3.01**	1.62	86	**2.95**	1.82	62
Revenue $/boe	**37.91**	28.25	34	**38.55**	25.37	52
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**60.35**	55.01	10	**62.51**	45.91	36
Hardisty Heavy (Cdn$/bbl)	**51.34**	42.09	22	**50.92**	33.43	52
AECO daily index (Cdn$/mcf)	**2.77**	1.39	99	**2.73**	1.61	70
AECO monthly index (Cdn$/mcf)	**2.76**	1.24	123	**2.84**	1.67	70
Royalty expenses ($ thousands)	**$6,986**	$1,049	566	**$13,627**	$2,829	382
$/boe	**3.97**	1.21	228	**4.05**	1.63	148
percent of sales	**10**	4	150	**11**	6	83

Revenue from crude oil, natural gas and associated natural gas liquids sales was $66.7 million in the second quarter of 2017, which was 6% higher than the $62.9 million generated in the first quarter of 2017. The 6% increase in second quarter 2017 revenue over the previous quarter is attributable to a 12% increase in crude oil and natural gas liquids production, a 4% increase in natural gas production and pricing for natural gas that was 4% higher, partially offset by crude oil and natural gas liquids pricing that was 7% lower.

Revenue in the second quarter of 2017 increased 172% from $24.5 million in the same period in 2016 primarily due to a 130% increase in crude oil and natural gas liquids production and a 74% increase in natural gas production, as well as 14% higher product prices for crude oil and natural gas liquids and 86% higher prices for natural gas.

Revenue for the six months ended June 30, 2017 increased 194% relative to the same period in 2016 primarily due to a 110% increase in crude oil and natural gas liquids production and a 76% increase in natural gas production, as well as 42% higher product prices for crude oil and natural gas liquids and

62% higher prices for natural gas.

WTI crude markets slid significantly through the first half of 2017 reaching a low point in June 2017 as a result of continued product oversupply. However, Canadian crude oil benchmarks benefitted in the second quarter of 2017 from a narrowing WTI to Edmonton differential and a weaker Canadian dollar, which resulted in a better price per barrel for the Edmonton Par Benchmark. During the second quarter, Edmonton Par was 10% higher than the same period in 2016, but decreased 7% quarter over quarter due to higher average WTI oil prices that prevailed in the first quarter. Tamarack's realized light oil price for the three months ended June 30, 2017 was $55.58/bbl versus $63.02/bbl in the previous quarter and $52.16/bbl in the second quarter of 2016 – a 12% decrease and 7% increase, respectively. The Company's realized oil price decreased to a greater degree than Edmonton Par due largely to differential hedges and the pricing received for its Viking oil. Tamarack maintains physical hedges on the WTI/Edmonton differential in order to protect against market volatility, and during the second quarter of 2017, the actual market differential was at a premium to the level contracted under the Company's physical hedges. In addition, the production contribution from Tamarack's Viking light oil has increased, and these barrels realize a lower price due to higher quality deductions stemming from their lower API gravity.

Conversely, natural gas liquids prices increased to $29.39/bbl from $26.46/bbl in the first quarter of 2017 and $21.57/bbl in the second quarter of 2016 – an 11% increase and a 36% increase, respectively. Natural gas liquids contracts are generally negotiated annually, with new contracts beginning April 1 each year. Realized natural gas liquids prices improved despite a decreasing Edmonton Par benchmark due to improved natural gas liquids contracts for the 2017 renewal period. Contract improvements for 2017 result from improved market conditions, including significantly improved propane prices and increased butane prices relative to the period when the 2016 contracts were negotiated, as well as the surplus of available liquids fractionation capacity in the province, which has resulted in more competitive product pricing and lower deductions.

While the Alberta AECO benchmark price remained relatively flat across the first half of 2017, subsequent to quarter end, cuts to deliveries in and out of Alberta have resulted in significant price reductions in the market. Challenges in the gas markets are expected to continue through most of the second half of 2017. Gas takeaway capacity and oversupply in Alberta continue to be significant issues in the province. Tamarack monitors these conditions and uses these factors to help make capital decisions and manage risk exposure. The AECO daily index increased 3% quarter-over-quarter and 99% over the second quarter of 2016. Second quarter 2017 realized prices averaged $3.01/mcf for natural gas compared to $2.89/mcf in the previous quarter and $1.62/mcf in the second quarter of 2016 – a 4% and 86% increase, respectively. A large majority of Tamarack's gas is priced relative to the AECO Daily (5A) index and should generally correlate to this index; however, realized pricing may not correlate quarter over quarter to the AECO Monthly (7A) index due to large daily fluctuations.

At June 30, 2017, the Company held derivative commodity and financial contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,300 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $68.40
Crude oil	400 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	US $55.23
Crude oil	2,000 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.83
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08
Crude oil	600 bbls/day	July 1, 2017 – December 31, 2017	Written call option	Cdn $81.90
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50
Crude oil	600 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $55.07
Natural gas	25,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.65
Natural gas	25,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.91
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16
Foreign exchange	330,000 US$/month	July 1, 2017 – March 31, 2018	Exchange rate	Cdn $1.34

At June 30, 2017, the commodity contracts were fair valued with an asset of $8.8 million (December 31, 2016 – $10.7 million liability) recorded on the balance sheet. The effect of the unrealized gains on the statement of comprehensive income included an increase to earnings of $19.7 million for the six months ended June 30, 2017 (loss of $15.0 million for the same period in 2016) and an increase to earnings of $8.8 million for the three months ended June 30, 2017 (loss of $12.9 million for the same period in 2016).

Subsequent to quarter end, prices in the AECO market have further decreased and the benchmark crude oil price continues to be volatile. If the unrealized hedging gains were valued at August 10, 2017 prices, the unrealized hedging gain would be higher than what was recorded at quarter end. If prices remain at these current levels, the Company expects to see both realized and unrealized gains greater than those recorded at quarter end.

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, 2017, the Company held the following physical commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.25
Crude oil	1,500 bbls/day	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.20
Crude oil	45,000 bbls/month	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.00

Since June 30, 2017, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude Oil	500 bbls/day	January 1, 2018 – December 31, 2018	WTI fixed price	US $52.00

Royalty expenses for the second quarter of 2017 were $3.97/boe or $7.0 million, representing 10% of revenue, comparable to $4.15/boe or $6.6 million for the first quarter of 2017, representing 11% of revenue.

Royalties as a percentage of revenue were higher in the second quarter of 2017 compared to the second quarter of 2016, when royalty expenses were $1.21/boe or $1.0 million, representing 4% of revenue. The increase in royalties as a percentage of revenue for the second quarter of 2017 over the same period in 2016 is due to the sliding scale mechanism which results in higher royalties when commodity prices increase, and the impact of the Viking Acquisition wells which have a slightly higher royalty rate.

The royalty expense for the first half of 2017 was $4.05/boe or $13.6 million, representing 11% of revenue, compared to $1.63/boe or $2.8 million, representing 6% of revenue for the same period in 2016. The increase in royalties as a percentage of revenue for the six months ended June 30, 2017 relative to the same period in 2016 is due to the sliding scale mechanism which results in higher royalties when commodity prices increase, and the impact of the Viking Acquisition wells which have a higher rate than the corporate average.

The Company expects royalty rates as a percentage of revenue to remain in the 10-13% range for the balance of 2017.

Production Expenses

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Total production expenses	**$20,859**	$9,593	117	**$39,150**	$19,747	98
Total ($/boe)	**$11.85**	$11.05	7	**$11.65**	$11.35	3

Production expenses for the second quarter of 2017 increased 4% to $11.85/boe compared to $11.42/boe incurred during the first quarter of 2017. The production costs on a per boe basis increased as a result of the Coleville Plant shut-down resulting in the redirection of production to third party facilities that had higher associated fees. This added approximately $0.58/boe to the quarterly per unit production costs. On an absolute basis, overall costs increased in the second quarter of 2017 to $20.9 million compared to $18.3 million in the first quarter of 2017. The increase in total production costs resulted from a 9% increase in production and the increase in per unit costs as described above.

On a per boe basis, second quarter 2017 production expenses were higher compared to the $11.05/boe realized in the same quarter of 2016, and increased 117% on an absolute basis to $20.9 million, compared to $9.6 million for the second quarter of 2016, matching the increase in production volumes during the same period.

Production expenses for the first half of 2017 increased by 3% to $11.65/boe compared to $11.35/boe for the same period in 2016, and increased 98% on an absolute basis to $39.2 million compared to $19.7 million for the same period in 2016. These increases tracked the increase in production volumes over the same period.

It is anticipated that production expenses per boe for the remainder of 2017 will remain in the $11.00 to $11.50 per boe range. The Company expects to reduce production costs on a per boe basis in the third quarter in the Veteran area due to the oil battery expansion and installation of water handling facilities that will significantly reduce water trucking and disposal costs. Lower per unit production costs on the Viking Acquisition assets are expected to be offset by cost increases associated with the recently legislated carbon tax in Alberta.

Operating Netback

($/boe)	Three months ended June 30, 2017	2016	% change	Six months ended June 30, 2017	2016	% change
Average realized sales	**$37.91**	$28.25	34	**$38.55**	$25.37	52
Royalty expenses	**(3.97)**	(1.21)	228	**(4.05)**	(1.63)	148
Production expenses	**(11.85)**	(11.05)	7	**(11.65)**	(11.35)	3
Operating field netback	**22.09**	15.99	38	**22.85**	12.39	84
Realized commodity hedging gain (loss)	**(0.19)**	4.69	(104)	**(0.47)**	5.96	(108)
Operating netback	**$21.90**	$20.68	6	**$22.38**	$18.35	22

Operating netback for the second quarter of 2017 decreased by 4% to $21.90/boe compared to $22.91/boe during the first quarter of 2017. This is attributable to a 7% decrease in oil and natural gas liquids prices ($51.77/bbl versus $55.74/bbl), a 4% increase in production expense per boe ($11.85/boe versus $11.42/boe), partially offset by a 4% increase in natural gas prices ($3.01/mcf versus $2.89/mcf) and a lower realized hedging loss in the second quarter of 2017 compared to the first quarter of 2017 (realized loss of $0.19/boe versus realized loss of $0.77/boe).

Second quarter 2017 operating netbacks were 6% higher than the $20.68/boe generated in the second quarter of 2016. This is attributable to a 14% increase in oil and natural gas liquids prices ($51.77/bbl versus $45.35/bbl) and an 86% increase in natural gas prices ($3.01/mcf versus $1.62/mcf). The increase was partially offset by a realized hedging loss in the second quarter of 2017 compared to a realized hedging gain in the second quarter of 2016 (realized loss of $0.19/boe versus realized gain of $4.69/boe), a 7% increase in production expense per boe ($11.85/boe versus $11.05/boe) and a 228% increase in royalty expense per boe ($3.97/boe versus $1.21/boe).

The first half of 2017 operating netbacks were 22% higher at $22.38/boe as compared to $18.35/boe generated for the same period in 2016. This is attributable to a 42% increase in oil and natural gas liquids prices ($53.63/bbl versus $37.90/bbl) and a 62% increase in natural gas prices ($2.95/mcf versus $1.82/mcf). The increases were partially offset by a realized hedging loss in the first half of 2017 compared to a realized hedging gain in the first half of 2016 (realized loss of $0.47/boe versus realized gain of $5.96/boe), a 3% increase in production expense per boe ($11.65/boe versus $11.35/boe) and a 148% increase in royalty expense per boe ($4.05/boe versus $1.63/boe).

General and Administrative Expenses

($ thousands, except per boe)	Three months ended June 30, 2017	2016	% change	Six months ended June 30, 2017	2016	% change
Gross costs	**$3,949**	$2,293	72	**$7,661**	$4,598	67
Capitalized costs and recoveries	**(891)**	(531)	68	**(1,671)**	(1,065)	57
General and administrative costs	**$3,058**	$1,762	74	**$5,990**	$3,533	70
Total ($/boe)	**$1.74**	$2.03	(14)	**$1.78**	$2.03	(12)

General and administrative ("G&A") expenses for the second quarter of 2017 were $1.74/boe on gross costs of $3.9 million compared to $1.83/boe on gross costs of $3.7 million in the first quarter of 2017. Second quarter 2017 gross G&A costs on an absolute basis were 6% higher than the previous quarter due to the full quarter effect of six new employees that were hired to support the Company's growth following the Viking Acquisition. Tamarack expects G&A costs per boe to remain in the $1.70/boe to $1.80/boe range for the rest of the year.

G&A costs per boe in the second quarter of 2017 were 14% lower than the $2.03/boe on gross costs of $2.3 million in the same period of 2016. Second quarter 2017 gross G&A costs on an absolute basis were 72% higher due to the impact of the Viking Acquisition.

For the first half of 2017, G&A costs were $1.78/boe on gross costs of $7.7 million compared to $2.03/boe on gross costs of $4.6 million in the same period of 2016. First half 2017 gross G&A costs on an absolute basis were 67% higher due to the impact of the Viking Acquisition.

Stock-Based Compensation Expenses

Stock-based compensation expenses relating to stock options and restricted share awards were $1.1 million and $2.2 million for the three and six months ended June 30, 2017, respectively, compared to $0.9 million and $1.9 million for the same periods in 2016. Stock-based compensation was higher for the three and six months ended June 30, 2017 due to the increased number of granted options and restricted shares during the fourth quarter of 2016, stemming from option and restricted share awards granted to new employees following the Viking Acquisition. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $0.5 million and $1.0 million of stock-based compensation expenses relating to exploration and development activities for the three and six months ended June 30, 2017, compared to capitalizing $0.4 million and $0.8 million for the same periods in 2016.

For the six months ended June 30, 2017, the Company issued 140,000 options at a weighted average exercise price of $3.01 per share and issued 262,275 restricted stock awards.

Interest

Interest expense was $1.8 million and $3.2 million for the three and six months ended June 30, 2017, compared to $0.8 million and $1.9 million for the same periods in 2016. The Company had $140.8 million drawn on its revolving credit facility at June 30, 2017, compared to $48.6 million drawn at June 30, 2016. Interest expense was higher for the three and six months ended June 30, 2017 compared to the same periods in 2016 due to a higher average amount drawn year-over-year on the revolving credit facility. The average amount drawn for the three and six months ended June 30, 2017 was approximately $143.9 million and $136.0 million, respectively, compared to an average amount drawn of approximately $49.1 million and $61.2 million during the same periods in 2016.

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, amortization and accretion expense (“DDA&A”).

($ thousands, except per boe)	Three months ended June 30, 2017	2016	% change	Six months ended June 30, 2017	2016	% change
Depletion and depreciation	**$35,687**	$14,924	139	**$67,547**	$30,074	125
Amortization of undeveloped leases	**196**	188	4	**393**	354	11
Accretion	**908**	326	179	**1,814**	673	170
Total	**$36,791**	$15,438	138	**$69,754**	$31,101	124
Depletion and depreciation ($/boe)	**$20.28**	$17.20	18	**$20.09**	$17.29	16
Amortization ($/boe)	**0.11**	0.22	(50)	**0.12**	0.20	(40)
Accretion ($/boe)	**0.52**	0.38	37	**0.54**	0.39	38
Total ($/boe)	**$20.91**	$17.80	17	**$20.75**	$17.88	16

For the second quarter of 2017, DDA&A expense was $20.91/boe compared to $20.58/boe in the first quarter of 2017. On an absolute basis, DDA&A expense was $36.8 million in the second quarter of 2017 compared to $33.0 million during the first quarter of 2017, related to the 9% increase in production and higher DDA&A expense on a per boe basis.

Second quarter 2017 DDA&A expense of $20.91/boe was higher relative to the $17.80/boe recorded for the same period in 2016. The increase in DDA&A rate was related to the Viking Acquisition assets having a higher DDA&A rate than Tamarack's legacy DDA&A rate. On an absolute basis, DDA&A expense of $36.8 million was 138% higher in the second quarter of 2017 compared to $15.4 million in the second quarter of 2016 due to a 103% increase in production and higher DDA&A expense on a per boe basis.

First half 2017 DDA&A expense of $20.75/boe was higher relative to the $17.88/boe recorded for the same period in 2016. The increase in DDA&A rate was related to the Viking Acquisition assets having a higher DDA&A rate than Tamarack's legacy DDA&A rate. On an absolute basis, DDA&A expense of $69.8 million was 124% higher in the first half of 2017 compared to $31.1 million in the first half of 2016 due to a 94% increase in production and higher DDA&A expense on a per boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three and six months ended June 30, 2017, nor does it expect to pay any cash taxes in 2017 or 2018 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and six months ended June 30, 2017, deferred income tax expenses of $1.5 million and $2.8 million, respectively, were recognized compared to a deferred income tax recovery of $3.5 million and $5.3 million for the same periods in 2016.

Funds from Operations and Net Income

($ thousands)	Three months ended June 30, 2017	2016	% change	Six months ended June 30, 2017	2016	% change
Petroleum and natural gas sales	**$66,715**	$24,517	172	**$129,585**	$44,136	194
Royalties	**(6,986)**	(1,049)	566	**(13,627)**	(2,829)	382
Realized gain (loss) on financial instruments	**(342)**	4,071	(108)	**(1,572)**	10,376	(115)
Production expenses	**(20,859)**	(9,593)	117	**(39,150)**	(19,747)	98
General and administration expenses	**(3,058)**	(1,762)	74	**(5,990)**	(3,533)	70
Interest	**(1,800)**	(820)	120	**(3,220)**	(1,864)	73
Funds from operations (excluding transaction costs)	**$33,670**	$15,364	119	**$66,026**	$26,539	149

Funds from operations excluding transaction costs during the second quarter of 2017 were $33.7 million ($0.15 per share basic and diluted) compared to $32.4 million ($0.15 per share basic and diluted) in the first quarter of 2017. The increase in the absolute amount is primarily the result of a 9% increase in production and a lower realized hedging loss in the second quarter of 2017 compared to the first quarter of 2017. These increases were partially offset by a 7% decrease in crude oil and natural gas liquids pricing, a 14% increase in production expenses and a 27% increase in interest expense.

Second quarter 2017 funds from operations excluding transaction costs were higher on an absolute basis than the same period in 2016 which totaled $15.4 million ($0.13 per share basic and diluted), primarily due to a 103% increase in production, a 14% increase in crude oil and natural gas liquids pricing, and an 85% increase in natural gas prices. The year-over-year increase was partially offset by a 566% increase in royalty expense, a 117% increase in production expenses, a 120% increase in interest expense, a 74% increase in G&A costs and a realized hedging loss in the second quarter of 2017 compared to a realized hedging gain in the second quarter of 2016.

Funds from operations excluding transaction costs during the first half of 2017 were $66.0 million ($0.30 per share basic and diluted) compared to $26.5 million ($0.24 per share basic and diluted) during the same period in 2016. The increase is primarily due to a 94% increase in production, a 42% increase in crude oil and natural gas liquids pricing, and a 62% increase in natural gas prices. The year-over-year increase was partially offset by a 382% increase in royalty expense, a 98% increase in production expenses, a 73% increase in interest expense, a 70% increase in G&A costs and a realized hedging loss in the first half of 2017 compared to a realized hedging gain in the first half of 2016.

($/boe)	Three months ended June 30, 2017	2016	% change	Six months ended June 30, 2017	2016	% change
Petroleum and natural gas sales	**$37.91**	$28.25	34	**$38.55**	$25.37	52
Royalties	**(3.97)**	($1.21)	228	**(4.05)**	(1.63)	148
Realized gain (loss) on financial instruments	**(0.19)**	$4.69	(104)	**(0.47)**	5.96	(108)
Production expenses	**(11.85)**	($11.05)	7	**(11.65)**	(11.35)	3
General and administration expenses	**(1.74)**	($2.03)	(14)	**(1.78)**	(2.03)	(12)
Interest	**(1.02)**	($0.95)	7	**(0.96)**	(1.07)	(10)
Funds from operations (excluding transaction costs)	**$19.14**	$17.70	8	**$19.64**	$15.25	29

On a per boe basis, second quarter 2017 funds from operations excluding transaction costs decreased 5% to $19.14/boe from $20.19/boe in the first quarter of 2017. The decrease is due to crude oil and natural gas liquids prices that were 7% lower and a 4% increase in production expenses per boe, partially offset by a 4% decrease in royalty expense per boe, a 4% increase in natural gas prices and a lower realized hedging loss in the second quarter of 2017 compared to the previous quarter.

Compared to funds from operations excluding transaction costs of $17.70/boe realized in the second quarter of 2016, funds from operations per boe in the second quarter of 2017 were 8% higher. The increase is due to a 14% increase in crude oil and natural gas liquids prices and an 86% increase in natural gas prices, partially offset by a 228% increase in royalty expense per boe, a 7% increase in production expenses per boe and a realized hedging loss in the second quarter of 2017 compared to a realized hedging gain in the same period of 2016.

On a per boe basis, funds from operations excluding transaction costs for the first half of 2017 increased 29% to $19.64/boe from $15.25/boe in the first half of 2016. The increase is due to a 42% increase in crude oil and natural gas liquids prices, a 62% increase in natural gas prices, a 12% decrease in G&A costs per boe and a 10% decrease in interest expense per boe. This increase was partially offset by a 148% increase in royalty expense per boe and a realized hedging loss in the first half of 2017 compared to a realized hedging gain in the first half of 2016.

The Company recorded net income of $3.1 million ($0.01 per share basic and diluted) during the three months ended June 30, 2017, compared to net income of $2.3 million ($0.01 per share basic and diluted) for the previous quarter. The increase is due primarily to higher oil and natural gas revenue, transaction costs of $5.7 million incurred in the first quarter of 2017 related to the Viking Acquisition and a lower realized loss on financial instruments in the second quarter of 2017 compared to the first quarter of 2017. These positive contributors to net income were partially offset by higher production expenses and higher DDA&A expense.

The Company recorded net income of $3.1 million ($0.01 per share basic and diluted) during the three months ended June 30, 2017, compared to a net loss of $10.4 million ($0.09 per share basic and diluted) for the same period in 2016. The factors contributing to net income in the second quarter of 2017 compared to a net loss in the same period in 2016 include higher oil and natural gas revenue and an $8.8 million unrealized gain on financial instruments compared to an unrealized loss of $12.9 million in the second quarter of 2016, which were partially offset by higher production expenses, higher royalty expenses, higher G&A expenses, higher interest expense and higher DDA&A expense.

The Company recorded net income of $5.3 million ($0.02 per share basic and diluted) during the six months ended June 30, 2017, compared to a net loss of $16.2 million ($0.15 per share basic and diluted) for the same period in 2016. The factors contributing to net income in the first half of 2017 compared to a net loss for the same period in 2016 include higher oil and natural gas revenue and a $19.7 million unrealized gain on financial instruments compared to an unrealized loss of $15.0 million in the first half of 2016. These were partially offset by $5.7 million in transaction costs related to the Viking Acquisition in the first quarter of 2017, higher production expenses, higher royalty expense, higher G&A expenses, higher interest expense and higher DDA&A expense.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

	Three months ended June 30,			Six months ended June 30,		
($ thousand)	**2017**	2016	% change	**2017**	2016	% change
Land	**$896**	$569	57	**$1,272**	$1,178	8
Geological and geophysical	**2,013**	1	201,200	**2,022**	413	390
Drilling and completion	**11,447**	6,574	74	**59,319**	20,820	185
Equipment and facilities	**3,950**	2,734	44	**18,532**	4,266	334
Capitalized G&A	**661**	291	127	**1,322**	527	151
Office equipment	**35**	140	(75)	**256**	254	1
Total capital expenditures	**$19,002**	$10,309	84	**$82,723**	$27,458	201

The Company's second quarter 2017 capital program of $19.0 million was lower relative to the first quarter level of $63.7 million; however, the capital spent was higher than originally forecasted due to the acceleration of the second half development program in response to mild spring break-up conditions for the month of June. This acceleration included drilling, completing and equipping five (4.9 net) Viking oil wells; and one (1.0 net) Mannville gas well. In addition, the Company completed and equipped five (4.3 net) Viking oil wells and three (3.0 net) Cardium oil wells that had been drilled in the first quarter of 2017.

The Company also allocated capital in the second quarter to improving operational efficiencies and investing in future development opportunities which will have a longer-term impact. These include the completion of the water disposal well and expansion of the oil battery in Veteran which is expected to significantly reduce water handling and disposal charges; tuck-in land acquisitions in Tamarack's core areas designed to increase the land base and inventory of future potential drilling locations; and the purchase of seismic in one of Tamarack's core areas which is expected to enhance the Company's knowledge of this area's geology and further develop additional assets within this area where the Company controls the infrastructure.

2017 Drilling Summary (including wells spudded by June 30, 2017)		
	Gross	Net
Heavy Oil	3.0	3.0
Viking	40.0	37.0
Mannville	2.0	2.0
Cardium	7.0	6.3
	52.0	48.3

The Company's net undeveloped land totaled 365,340 acres at the end of the second quarter of 2017.

Acquisitions

During the three and six months ended June 30, 2017, costs of $1.3 million and $77.3 million, respectively, were incurred related to corporate and property acquisitions. The Viking Acquisition accounted for $0.5 million during the second quarter and $0.8 million was related to the Redwater Acquisition that closed in the third quarter of 2016.

The Viking Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of January 11, 2017. The allocation of the purchase price, based on management's preliminary estimate of fair values, is outlined in the table below:

Consideration (thousands):		
Cash consideration	$	57,631
Share consideration (90,142,906 common shares)		310,092
Total consideration	$	367,723
Net Assets Acquired (thousands):		
Current assets	$	39,684
Current liabilities		(10,517)
Risk management contracts		(269)
Bank debt		(47,115)
Property, plant and equipment		480,076
Decommissioning obligations		(19,207)
Deferred tax liability		(74,929)
Net assets	$	367,723

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

The fair value of property, plant and equipment has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk free rate of 8%**.**

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency but excluding the fair value of financial instruments, totaled $152.4 million as at June 30, 2017. This compares to the previous quarter of 2017 and the same quarter of 2016, which recorded net debt of $165.6 million and $57.8 million, respectively. Tamarack's second quarter 2017 net debt to annualized funds from operations was 1.1 times as compared to the first quarter 2017 net debt to annualized funds from operations excluding transaction costs of 1.3 times.

At June 30, 2017, Tamarack had 227,673,382 common shares, 5,467,051 options and 3,322,441 restricted share awards outstanding. At August 10, 2017, there were 227,653,382 common shares, 5,467,051 options and 3,302,441 restricted share awards outstanding. This compares to December 31, 2016 at which time there were 137,527,475 common shares, 5,327,051 options and 3,063,167 restricted share awards outstanding. The Company had 227,671,832 and 222,690,839 weighted average basic common shares outstanding during the three and six months ended June 30, 2017. No preferred shares of Tamarack are issued and outstanding.

On January 11, 2017, the Company issued 90,142,906 common shares on closing of the Viking Acquisition.

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2.5 million. Under the terms of the flow-through share agreements, the Company is required to incur the expenditures by December 31, 2017. As of June 30, 2017, the Company had incurred $2.4 million of qualifying expenditures.

At June 30, 2017 and December 31, 2016, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at June 30, 2017 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share. An exchange of the TAC Preferred Shares is at the election of the Company under certain circumstances.

The Company currently has a revolving credit facility in the amount of $245 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $265 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 25, 2018. If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date on May 25, 2019.

The interest rate on the 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 Facility. The Facility has been secured by a $550 million supplemental debenture with a floating charge over all assets. As the available lending limits of the two facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for November 2017.

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 acquisitions within its core areas while commodity prices are low. The Viking Acquisition that closed on January 11, 2017 is consistent with this strategy. Tamarack will continue to execute its successful strategy of focusing 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 production costs in order to optimize capital efficiencies.

2017 Guidance

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

- Annual average production between 19,000-20,000 boe/d (approximately 55-60% liquids), with 2017 exit production estimated at approximately 22,000 boe/d (approximately 57-62% liquids);
- Planned capital expenditure range of $165 to $175 million, with second half 2017 expenditures of $80 to $90 million;
- Estimated year end 2017 net debt to fourth quarter annualized funds flow (including hedges) ratio below 1.0 times with an estimated $95-105 million of liquidity on the Company's existing credit facilities; and
- Using assumed second half 2017 commodity prices: WTI averaging $48.50/bbl USD, Edmonton Par price averaging $58.40/bbl, AECO averaging $2.25/GJ and a Canadian/US dollar exchange rate of $0.79.

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

Commitments

The following table summarizes the Company's commitments at June 30, 2017:

($ thousands)	2017	2018	2019	2020	2021	2022	2023
Office lease	317	542	542	263	–	–	–
Flow-through shares	122	–	–	–	–	–	–
Take or pay commitments[1]	493	986	–	–	–	–	–
Rental fee[2]	2,585	5,170	5,170	5,170	5,170	3,299	714
Total	3,517	6,698	5,712	5,433	5,170	3,299	714

(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 18 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $0.1 million 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 to 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 corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and production 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 and transaction costs related to acquisitions or dispositions, 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,	
($ thousands)	**2017**	2016	**2017**	2016
Cash provided by operating activities	**$34,537**	$14,560	**$59,232**	$29,043
Abandonment expenditures	**160**	30	**361**	183
Transaction costs	**–**	–	**5,663**	96
Changes in non-cash working capital	**(1,027)**	774	**770**	(2,783)
Funds from operations	**$33,670**	$15,364	**$66,026**	$26,539
Funds from operation per share - basic	**$ 0.15**	$ 0.13	**$ 0.30**	$ 0.24
Funds from operation per share - diluted	**$ 0.15**	$ 0.13	**$ 0.29**	$ 0.24

(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 production costs calculated on a per boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates 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):

($ thousand)	June 30, 2017	December 31, 2016
Bank debt	$140,795	$45,227
Accounts payable and accrued liabilities	40,544	25,015
Accounts receivable	(27,013)	(16,557)
Prepaid expenses and deposits	(1,972)	(1,369)
Net debt	$152,354	$52,316

Selected Quarterly Information

Three months ended	**Jun. 30, 2017**	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015
Sales volumes								
Natural gas *(mcf/d)*	**47,696**	45,852	31,226	29,007	27,462	25,818	23,229	22,005
Oil and NGLs *(bbls/d)*	**11,387**	10,154	6,249	5,955	4,959	5,279	6,096	5,049
Average boe/d *(6:1)*	**19,336**	17,796	11,453	10,790	9,536	9,582	9,968	8,717
Product prices								
Natural gas *($/mcf)*	**3.01**	2.89	3.27	2.54	1.62	2.03	2.66	3.04
Oil and NGLs *($/bbl)*	**51.77**	55.74	52.88	45.29	45.35	30.90	39.30	46.56
Oil equivalent *($/boe)*	**37.91**	39.25	37.76	31.82	28.25	22.50	30.23	34.64
(000s, except per share amounts)								
Financial results								
Gross revenues	**66,715**	62,870	39,793	31,588	24,517	19,619	27,725	27,779
Funds from operations	**33,670**	26,693	20,453	16,672	15,364	11,078	18,615	14,618
Per share – basic	**0.15**	0.12	0.15	0.12	0.13	0.11	0.19	0.15
Per share – diluted	**0.15**	0.12	0.15	0.12	0.13	0.11	0.18	0.15
Net income (loss)	**3,053**	2,290	(8,424)	(3,195)	(10,368)	(5,835)	5,119	(15,064)
Per share – basic	**0.01**	0.02	(0.06)	(0.02)	(0.09)	(0.06)	0.05	(0.15)
Per share – diluted	**0.01**	0.02	(0.06)	(0.02)	(0.09)	(0.06)	0.05	(0.15)
Additions to property and equipment, net of proceeds	**19,002**	63,721	12,665	14,497	10,309	17,149	8,743	21,936
Net acquisitions	**1,301**	75,995	(248)	85,857	–	–	2,075	1,230
Total assets	**1,178,404**	1,186,285	663,564	679,259	542,917	553,135	549,068	549,652
Net debt[(1)]	**(152,354)**	(165,561)	(52,316)	(62,817)	(57,791)	(62,696)	(97,941)	(105,837)
Bank debt	**140,795**	135,484	45,227	48,598	48,630	50,056	82,822	94,423
Decommissioning obligations	**171,909**	164,012	112,115	122,810	68,149	65,643	63,331	61,808
Deferred income tax liability (asset)	**36,762**	35,149	(47,714)	(41,496)	(42,116)	(38,576)	(36,168)	(35,770)

(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 Cash Generating Units (“CGUs”) due to falling oil and gas prices in the amount of $29.1 million in the third quarter of 2015.
- On January 11, 2017, Tamarack closed the Viking Acquisition which added assets in Southeast Alberta and Southwest Saskatchewan; in the first half of 2017 this acquisition added $38.7

million to oil and natural gas revenue and contributed $1.2 million to net loss.

- During the third quarter of 2016, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny and Redwater Acquisitions") on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $6.3 million to oil and natural gas revenue and contributed $0.5 million to net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and $0.5 million in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions.

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) **Carrying Value of Property, Plant & Equipment** – 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.

E&E 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. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined, which is considered to be 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) **Stock-based compensation –** The Company uses the fair value method for valuing stock option grants. Under this method, compensation cost attributable to all stock options 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 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 recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Business Risks

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

Financial Risks

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

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

Operational Risks

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

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

Insurance is in place to protect against major asset destruction or business interruption, including well blow-outs and pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the prevailing 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 in a cost-effective manner.

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 Canadian securities legislation. 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", "endeavour", "continue", "estimate", "evaluate", "expect", "forecast", "monitor", "may", "will", "can", "able", "potential", "target", "intend", "consider", "focus", "identify", "use", "utilize", "manage", "maintain", "remain", "result", "cultivate", "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.

Without limitation, this MD&A contains forward-looking statements pertaining to:

- the intentions of management and the Company;
- the availability, terms, use and renewal of credit facilities;
- no immediate requirement for equity to fund development of the assets in 2017;

- estimated production rates in 2017;
- the timeframe for resumption of full operations at the Coleville Plant;
- the effect of the recently legislated carbon tax in Alberta;
- future production costs and G&A expenses;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing production costs on newly acquired assets;
- Tamarack's primary focus areas for production growth;
- the completion of the waste disposal well and expansion of the oil battery in Veteran and expected reductions of water handling and disposal charges;
- tuck-in acquisitions in Tamarack's core areas;
- future drilling plans;
- deferred tax liabilities;
- future capital expenditures and capital program funding;
- the purchase of seismic in one of Tamarack's core areas;
- estimated year end debt to cash flow (including hedges) ratio;
- the Company's capital program and guidance for 2017;
- derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities;
- expectations as to oil and natural gas pricing in 2017;
- expectations as to oil and natural gas weighting in 2017; and
- 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 and the actual prices received for the Company's products;
- expected production costs and G&A expenses;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions and the Viking Acquisition;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- 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 material uncertainties and risks described under the headings "Critical Accounting Estimates", "Disclosure Controls and Internal Controls Over Financial Reporting", "Business Risks", "Financial Risks", "Operational Risks" and "Regulatory Risks";
- the material assumptions and observations described under the headings "Production", "Petroleum, Natural Gas Sales and Royalties", "Production Expenses", "Operating Netback", "General and Administrative Expenses", "Stock-Based Compensation Expenses", "Interest", "Depletion, Depreciation, Amortization and Accretion", "Income Taxes", "Funds from Operations and Net Income", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Acquisitions", "Liquidity and Capital Resources", "2017 Guidance", "Commitments" and "Selected Quarterly Information";
- 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 and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to market for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- production and transportation costs and future development costs;
- 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. The risk factors above should be considered in the context of current economic conditions, in particular low prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2016, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited) (thousands)

	June 30, 2017	December 31, 2016
Assets		
Current assets:		
Accounts receivable	$27,013	$16,557
Prepaid expenses and deposits	1,972	1,369
Fair value of financial instruments (note 3)	8,758	–
	37,743	17,926
Property, plant and equipment (note 5)	1,138,521	601,420
Exploration and evaluation assets (note 6)	2,140	2,504
Deferred tax asset	–	41,714
	$1,178,404	$663,564
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$40,544	$25,015
Fair value of financial instruments (note 3)	–	10,704
	40,544	35,719
Bank debt (note 11)	140,795	45,227
Decommissioning obligations (note 7)	171,909	112,115
Deferred flow-through share premium	37	765
Deferred tax liability	36,762	–
Shareholders' equity:		
Share capital (note 9)	847,648	537,554
Contributed surplus	25,124	21,942
Deficit	(84,415)	(89,758)
	788,357	469,738
Commitments and contingencies (note 13)		
	$1,178,404	$663,564

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
For the three and six months ended June 30, 2017 and 2016
(unaudited) (thousands, except per share amounts)

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Revenue:				
Oil and natural gas	$66,715	$24,517	$129,585	$44,136
Royalties	(6,986)	(1,049)	(13,627)	(2,829)
Realized gain (loss) on financial instruments (note 3)	(342)	4,071	(1,572)	10,376
Unrealized gain (loss) on financial instruments (note 3)	8,795	(12,883)	19,730	(14,987)
	68,182	14,656	134,116	36,696
Expenses:				
Production	20,859	9,593	39,150	19,747
General and administration	3,058	1,762	5,990	3,533
Transaction costs (note 4)	–	–	5,663	96
Stock-based compensation (note 12)	1,101	910	2,171	1,862
Finance	2,708	1,146	5,034	2,537
Depletion, depreciation and amortization	35,883	15,112	67,940	30,428
	63,609	28,523	125,948	58,203
Income (loss) before taxes	4,573	(13,867)	8,168	(21,507)
Deferred income tax recovery (expense)	(1,520)	3,499	(2,825)	5,305
Net income (loss) and comprehensive income (loss)	$3,053	$(10,368)	$5,343	$(16,202)
Net income (loss) per share (note 10):				
Basic	$ 0.01	$(0.09)	$ 0.02	$(0.15)
Diluted	$ 0.01	$(0.09)	$ 0.02	$(0.15)

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Shareholders' Equity
(unaudited) (thousands)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2017	137,527	$537,554	$21,942	$(89,758)	$469,738
Issue of common shares	90,146	310,092	–	–	310,092
Share issue costs, net of tax of $5.5	–	(15)	–	–	(15)
Transfer on exercise of stock options	–	17	(17)	–	–
Stock-based compensation	–	–	3,199	–	3,199
Net income	–	–	–	5,343	5,343
Balance at June 30, 2017	227,673	$847,648	$25,124	$(84,415)	$788,357

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2016	99,971	$416,075	$17,044	$(61,935)	$371,184
Issue of common shares	14,982	43,734	–	–	43,734
Share issue costs, net of tax of $643.7	–	(1,740)	–	–	(1,740)
Transfer on exercise of stock options	–	21	(21)	–	–
Stock-based compensation	–	–	2,659	–	2,659
Net loss	–	–	–	(16,202)	(16,202)
Balance at June 30, 2016	114,953	$458,090	$19,682	$(78,137)	$399,635

See accompanying notes 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, 2017 and 2016
(unaudited) (thousands)

	Three Months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash provided by (used in):				
Operating:				
Net income (loss)	$3,053	$(10,368)	$5,343	$(16,202)
Items not involving cash:				
Depletion, depreciation and amortization	35,883	15,112	67,940	30,428
Stock-based compensation	1,101	910	2,171	1,862
Accretion expense on decommissioning obligations	908	326	1,814	673
Unrealized loss (gain) on financial instruments	(8,795)	12,883	(19,730)	14,987
Deferred income tax expense (recovery)	1,520	(3,499)	2,825	(5,305)
Funds from operations	33,670	15,364	60,363	26,443
Abandonment expenditures (note 7)	(160)	(30)	(361)	(183)
Changes in non-cash working capital (note 8)	1,027	(774)	(770)	2,783
Cash provided by operating activities	34,537	14,560	59,232	29,043
Financing:				
Change in bank debt	5,311	(1,426)	95,568	(34,192)
Proceeds from issuance of shares	–	33	–	43,733
Share issue costs	–	(152)	(21)	(2,384)
Cash provided by (used in) financing activities	5,311	(1,545)	95,547	7,157
Investing:				
Property, plant and equipment additions (note 5)	(16,989)	(9,699)	(77,105)	(25,741)
Exploration and evaluation additions (note 6)	(2,013)	(610)	(5,618)	(1,717)
Acquisitions (note 4)	(1,301)	–	(106,463)	–
Changes in non-cash working capital (note 8)	(19,545)	(2,706)	34,407	(8,742)
Cash used in investing activities	(39,848)	(13,015)	(154,779)	(36,200)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. 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 11, 2017, Tamarack Acquisition Corp. and Spur Resources Ltd., completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp".

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, 2016. 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, 2016.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on August 10, 2017.

3. Commodity contracts:

It is the Company's policy to economically hedge some oil and natural gas sales using 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 based on 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 its expected sales 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 fair value to profit and loss and therefore the carrying amount equals fair value.

At June 30, 2017, the Company held derivative commodity and financial contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	2,300 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $68.40	$1,898
Crude oil	400 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	US $55.23	$448
Crude oil	2,000 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.83	$1,792
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08	$591
Crude oil	600 bbls/day	July 1, 2017 – December 31, 2017	WTI written call option	Cdn $81.90	($6)
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50	$210
Crude oil	600 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $55.07	$532
Natural gas	25,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.65	$801
Natural gas	25,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.91	$1,002
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16	$1,067
Foreign exchange	330,000 US$/mth	July 1, 2017 – March 31, 2018	Exchange rate	Cdn $1.34	$423
					$8,758

At June 30, 2017, the commodity contracts were fair valued with an asset of $8.8 million (December 31, 2016 - $10.7 million liability) recorded on the balance sheet and an unrealized gain of $19.7 million 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, 2017, the Company held the following physical commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.25
Crude oil	1,500 bbls/day	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.20
Crude oil	45,000 bbls/month	July 1, 2017 – December 31, 2017	WTI/Edm Differential	US $3.00

The assets and liabilities of risk management contracts are offset and the net amount presented on 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 (thousands)	**June 30, 2017**	December 31, 2016
Risk management contracts		
Current asset	**$8,764**	$ –
Current liability	**(6)**	(10,704)
Balance, end of the period	**$8,758**	$(10,704)

Since June 30, 2017, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude Oil	500 bbls/day	January 1, 2018 – December 31, 2018	WTI fixed price	US $52.00

4. Corporate acquisition:

On January 11, 2017, Tamarack acquired Spur Resources Ltd. (“Spur”) by acquiring all of the issued and outstanding common shares of Spur with the issuance of 90.1 million common shares of the Company and $57.8 million of cash (the “Viking Acquisition”). The Viking Acquisition builds upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. The operations from the Viking Acquisition have been included in Tamarack’s results commencing on January 11, 2017. Based upon Tamarack’s share price on the date of closing being January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack was approximately $367.7 million.

The Company incurred transaction costs of $5.7 million in connection with the Viking Acquisition which is recorded in earnings.

The Viking Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of January 11, 2017. The allocation of the purchase price, based on management’s preliminary estimate of fair values, is as follows:

Consideration (thousands):	
Cash consideration	$ 57,631
Share consideration (90,142,906 common shares)	310,092
Total consideration	$ 367,723
Net Assets Acquired (thousands):	
Current assets	$ 39,684
Current liabilities	(10,517)
Risk management contracts	(269)
Bank debt	(47,115)
Property, plant and equipment	480,076
Decommissioning obligations	(19,207)
Deferred tax liability	(74,929)
Net assets	$ 367,723

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

The fair value of property, plant and equipment has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk free rate of 8%.

Oil and natural gas revenue of $38.7 million and a net loss of $1.2 million are included in the statement of income for the Viking Acquisition properties since the closing date of January 11, 2017.

If the acquisition had occurred on January 1, 2017, the incremental oil and natural gas revenue and income recognized for the period ended June 30, 2017 and the pro forma results would have been as follows:

Period ended June 30, 2017 (thousands)	As stated	Spur Resources Ltd. Prior to Acquisition	(unaudited) Pro Forma
Oil and natural gas revenue	$129,585	$2,616	$132,201
Net income (loss)	5,343	(227)	5,116

(1) This pro forma information is not necessarily indicative of results of operations that would have resulted had the acquisition been effected on the dates indicated.

5. Property, plant and equipment:

($ thousands)	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2016	$716,388	$601	$716,989
Property acquisition	105,093	–	105,093
Cash additions	53,401	433	53,834
Decommissioning costs	28,622	–	28,622
Stock-based compensation	1,479	–	1,479
Transfer from exploration and	–	–	–
evaluation assets	1,212	–	1,212
Disposals	(7,025)	–	(7,025)
Balance at December 31, 2016	899,170	1,034	900,204
Corporate acquisition (note 4)(1)	481,793	–	481,793
Cash additions	76,840	265	77,105
Decommissioning costs	39,134	–	39,134
Stock-based compensation	1,028	–	1,028
Transfer from exploration and evaluation assets	5,588	–	5,588
Balance at June 30, 2017	$1,503,553	$1,299	$1,504,852

Depletion, depreciation and impairment losses:			
Balance at January 1, 2016	$235,109	$265	$235,374
Depletion and depreciation	64,494	173	64,667
Impairment loss	(1,257)	–	(1,257)
Balance at December 31, 2016	298,346	438	298,784
Depletion and depreciation	67,445	102	67,547
Balance at June 30, 2017	$365,791	$540	$366,331

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2016	$600,824	$596	$601,420
At June 30, 2017	$1,137,762	$759	$1,138,521

(1) Includes $1.7 million of minor property acquisitions.

The calculation of depletion at June 30, 2017 includes estimated future development costs of $549 million (December 31, 2016 – $401 million) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $38.8 million (December 31, 2016 – $32.8 million).

6. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2016	$22,083
Additions	2,985
Transfer to property, plant and equipment	(1,212)
Balance at December 31, 2016	23,856
Additions	5,618
Transfer to property, plant and equipment	(5,588)
Balance at June 30, 2017	$23,886
Amortization and impairment:	
Balance at January 1, 2016	$19,878
Amortization	760
Impairment loss	715
Balance at December 31, 2016	21,353
Amortization	393
Balance at June 30, 2017	$21,746

	Total
Carrying amounts:	
At December 31, 2016	$2,504
At June 30, 2017	$2,140

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.

7. 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 and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $168.0 million at June 30, 2017 (December 31, 2016 – $114.3 million), which is expected to be incurred between 2017 and 2041. A risk-free rate of 2.1% (December 31, 2016 – 2.3%) and an inflation rate of 2% (December 31, 2016 – 2%) is used to calculate the present value of the decommissioning obligations at June 30, 2017 as presented in the table below:

($ thousands)	**June 30, 2017**	December 31, 2016
Balance, beginning of the period	**$112,115**	$63,331
Liabilities incurred	**3,216**	1,546
Liabilities acquired (note 4)	**19,207**	20,782
Change in estimates	**6,717**	(5,970)
Change in discount rate on acquisition	**29,201**	33,045
Expenditures	**(361)**	(218)
Liabilities disposed	**–**	(2,097)
Accretion	**1,814**	1,696
Balance, end of the period	**$171,909**	$112,115

The decommissioning obligations acquired in the Viking Acquisition were initially recognized using a credit-adjusted risk free discount rate of 8%. It was subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

The change in estimates for 2017 resulted from decommissioning obligations being revalued using a risk-free rate of 2.1% as opposed to the risk-free rate of 2.3% used in 2016.

8. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2017**	2016	**2017**	2016
Source/(use of cash):				
Accounts receivable	**$6,270**	$1,097	**$(10,456)**	$1,726
Prepaid expenses and deposits	**1,069**	94	**(603)**	59
Accounts payable and accrued liabilities	**(25,857)**	(4,671)	**15,529**	(7,744)
Working capital acquired (note 4)	**–**	–	**29,167**	–
	$(18,518)	$(3,480)	**$33,637**	$(5,959)
Related to operating activities	**$1,027**	$(774)	**$(770)**	$2,783
Related to investing activities	**$(19,545)**	$(2,706)	**$34,407**	$(8,742)

Cash interest paid during the quarter was $1.8 million and for the six months ended June 30, 2017 was $3.2 million (December 31, 2016 – $3.4 million).

9. Share capital:

At June 30, 2017, the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

On January 11, 2017, the Company issued 90.1 million common shares in connection with the Viking Acquisition (note 4).

On December 29, 2016, the Company issued 0.5 million flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2.5 million. Under the terms of the flow-through share agreements, the Company is required to incur the expenditures by December 31, 2017. As of June 30, 2017, the Company has incurred $2.4 million of qualifying expenditures.

During the six months ended June 30, 2017 there were 3,001 restricted share awards converted to common shares.

10. Income (loss) per share:

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	**2017**	2016	**2017**	2016
Net income (loss)	**$3,053**	$(10,368)	**$5,343**	$(16,202)
Weighted average shares - basic	**227,672**	114,945	**222,691**	108,610
Weighted average shares - diluted	**229,066**	114,945	**224,419**	108,610
Net income (loss) per share-basic	**$ 0.01**	$(0.09)	**$ 0.02**	$(0.15)
Net income (loss) per share-diluted	**$ 0.01**	$(0.09)	**$ 0.02**	$(0.15)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and six months ended June 30, 2017, 1.4 million and 1.7 million, respectively, stock options, preferred shares and restrictive stock units were included in the diluted earnings per share. For the three and six months ended June 30, 2016, 7.6 million stock options, preferred shares and restrictive stock units were excluded from the diluted earnings per share as they were anti-dilutive.

11. Bank debt:

The Company currently has available a revolving credit facility in the amount of $245 million and a $20 million operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility, totaling $265 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 25, 2018. If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 25, 2019.

The interest rate on the 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 Facility. The Facility has been secured by a $550 million supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for November 2017.

At June 30, 2017, the Company had utilized the Facility in the amount of $140.8 million. As at June 30, 2017, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility.

12. Share-based payments:

(a) Preferred share plan:

There are 1.2 million preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1.1 million common shares of the Company (December 31, 2016 – 1.1 million). The preferred shares of Tamarack Acquisition Corp. are fully vested at June 30, 2017 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 22.8 million options or restricted share units to its employees, directors and consultants of which 8.8 million options 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 0.1 million options granted during the period.

The fair value of each option granted during the six months ended June 30, 2017 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2017
Risk free rate (%)	**1.02**
Expected volatility (%)	**80**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**2.00**

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

	Number of options (thousands)	Weighted average exercise price
Outstanding, January 1, 2016	4,669	$ 3.59
Granted	945	3.44
Exercised	(16)	2.06
Expired	(271)	4.55
Outstanding, December 31, 2016	5,327	$ 3.52
Granted	140	3.01
Outstanding, June 30, 2017	**5,467**	**$ 3.50**

The following table summarizes information about stock options outstanding and exercisable at June 30, 2017:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 1.86 – 3.00	1,827	$2.38	1.6	1,324	$2.23
$ 3.01 – 5.00	3,174	$3.66	2.4	2,096	$3.73
$ 5.01 – 6.82	466	$6.82	2.1	311	$6.82
$ 1.86 – 6.82	**5,467**	**$3.50**	**2.1**	**3,731**	**$3.46**

(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. There were 0.3 million restricted stock units granted during the period.

For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards:

	Number of awards (thousands)
Outstanding, January 1, 2016	1,861
Granted	1,214
Exercised	(12)
Outstanding, December 31, 2016	3,063
Granted	262
Exercised	(3)
Outstanding, June 30, 2017	**3,322**
Exercisable, June 30, 2017	**743**

13. Commitments and contingencies:

(a) Commitments:

The following table summarizes the Company's commitments at June 30, 2017:

($ thousands)	2017	2018	2019	2020	2021	2022	2023
Office lease	317	542	542	263	–	–	–
Flow-through shares	122	–	–	–	–	–	–
Take or pay commitments[1]	493	986	–	–	–	–	–
Rental fee[2]	2,585	5,170	5,170	5,170	5,170	3,299	714
Total	3,517	6,698	5,712	5,433	5,170	3,299	714

(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 18 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $0.1 million 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.

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

Dean Setoguchi(1)

David Mackenzie(1)(2)

Jeff Boyce(1)(2)

Noralee Bradley(3)(4)

John Leach(1)(3)

Ian Currie(2)(4)

Rob Spitzer(3)(4)

Brian Schmidt

(1) Member of the 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
(4) Member of the Health, Safety & Environmental 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

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

McCarthy Tétrault

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

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