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, 2015 and 2014. This MD&A is dated and based on information available on August 12, 2015 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, 2015 and 2014. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

The condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS and additional IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to section entitled "Non-IFRS and Additional IFRS Measures" on page 14. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Unit Cost Calculation

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

Abbreviations

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

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

About Tamarack

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

Late in the second quarter of 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta for an aggregate cash purchase price of $55.0 million, prior to closing adjustments (the “Alder Flats Acquisition”).

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

Production

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Production						
Light oil (bbls/d)	**3,029**	2,799	8	**3,525**	2,451	44
Heavy oil (bbls/d)	**627**	179	250	**563**	132	327
Natural gas liquids (bbls/d)	**507**	219	132	**548**	185	196
Natural gas (mcf/d)	**16,972**	12,033	41	**17,415**	11,565	51
Total (boe/d)	**6,992**	5,203	34	**7,539**	4,696	61
Percentage of oil and natural gas liquids	**60%**	61%		**61%**	59%	

Average production for the second quarter of 2015 increased by 34% to 6,992 boe/d from 5,203 boe/d in the second quarter of 2014. Compared to the first quarter of 2015, production in the second quarter of 2015 decreased by 14% from 8,092 boe/d. The production decrease was mainly the result of the Company shutting down its drilling operations during the first quarter in response to the decrease in commodity prices. The Company did not bring on any new wells until June 2015, resulting in only 16 boe/d of new production compared to a full quarter of flush production from the 13 (10.9 net) Cardium oil wells drilled in the fourth quarter of 2014, which added 1,527 boe/d to the first quarter average. Also contributing to the production decline in the second quarter of 2015 were normal declines from existing production, TransCanada Pipeline (“TCPL”) curtailments and the shut-down of a non-operated gas facility, which resulted in approximately 440 boe/d of lost production to the quarter average. This was partially offset by the Alder Flats Acquisition, which added 352 boe/d to the quarter average, and improvement in field performance in Hatton, which added 130 boe/d to the quarter average.

Average crude oil and natural gas liquids production in the second quarter of 2015 decreased 19% to 4,163 bbls/d compared to 5,115 bbls/d in the first quarter of 2015. Crude oil and natural gas liquids production decreased 19% quarter-over-quarter for the same reasons that led to a decline in overall production. As noted above, the Company did not bring on any new wells until June 2015, resulting in only 13 bbls/d of new production coming on-stream compared to a full quarter of flush production from the oil wells drilled in the fourth quarter of 2014, which added 1,166 bbls/d to the first quarter average. Also contributing to the production decline in the second quarter of 2015 were normal declines from existing production, partially offset by the Alder Flats Acquisition, which added 157 bbls/d to the quarter average and improvement in field performance in Hatton, which added 130 bbls/d to the quarter average.

Tamarack's oil and natural gas liquids weighting decreased to 60% of total production in the second quarter of 2015 compared to 63% during the first quarter of 2015. The Company expects its oil and natural gas liquids weighting to fluctuate between 55% and 64% depending on the timing of production additions from the Redwater and Wilson Creek areas, where production will be weighted higher to liquids content, as compared to the Alder Flats and Brazeau areas, which have a higher natural gas weighting.

Natural gas production averaged 16,972 mcf/d in the second quarter of 2015 compared to 17,864 mcf/d in the first quarter of 2015 for the same reasons that led to a decline in overall production. The Company didn't bring on any new wells until June 2015, resulting in only 18 mcf/d of new production coming on-stream compared to a full quarter of flush production from the wells drilled in the fourth quarter of 2014, which added 2,168 mcf/d to the first quarter average. Also contributing to the production decline in the second quarter of 2015 were normal declines from existing production, pipeline curtailments and the shut-down of a non-operated gas facility, which resulted in approximately 1,200 mcf/d of lost production to the quarter average. The decline in natural gas production was partially offset by the Alder Flats Acquisition, which added 1,170 mcf/d to the quarter.

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

Late in the second quarter of 2015, the Company fracture stimulated 4 (2.4 net) horizontal Cardium wells that were drilled in late 2014 and early 2015. The Company also commenced its second half 2015 drilling program on May 25, 2015 with 4 (4.0 net) horizontal Cardium oil wells drilled and completed in the Wilson Creek area and a fifth well currently being drilled. These new Wilson Creek wells only contributed 16 boe/d average production during the second quarter of 2015 due to the timing of wells coming on-stream. Third quarter production is expected to be enhanced by the full production impact of these 8 (6.4 net) new wells expected to come on production at various times during the quarter.

Production as of July 29, 2015, based on field estimates, was approximately 8,525 boe/d (58% oil & NGLs) with 6 (4.4 net) wells still waiting to be brought on production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Revenue						
Oil and NGLs	**$21,012,854**	$27,537,244	(24)	**$41,641,249**	$47,112,715	(12)
Natural gas	**4,317,689**	4,785,021	(10)	**8,999,927**	9,707,805	(7)
Total	**$25,330,543**	$32,322,265	(22)	**$50,641,176**	$56,820,520	(11)
Average realized price						
Light oil ($/bbl)	**61.21**	94.82	(35)	**53.89**	97.13	(45)
Heavy oil ($/bbl)	**51.73**	77.30	(33)	**46.21**	77.48	(40)
Natural gas liquids ($/bbl)	**25.87**	79.84	(68)	**25.63**	65.18	(61)
Combined average oil and NGLs ($/boe)	**55.47**	94.65	(41)	**49.62**	94.05	(47)
Natural gas ($/mcf)	**2.80**	4.37	(36)	**2.86**	4.64	(38)
Revenue $/boe	**39.82**	68.27	(42)	**37.11**	66.86	(44)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**68.49**	104.13	(34)	**60.59**	101.86	(41)
Hardisty Heavy (Cdn$/bbl)	**57.41**	90.69	(37)	**50.07**	87.30	(43)
AECO daily index (Cdn$/mcf)	**2.65**	4.67	(43)	**2.70**	5.17	(48)
AECO monthly index (Cdn$/mcf)	**2.66**	4.66	(43)	**2.80**	4.70	(40)
Royalty expenses	**$2,192,889**	$4,201,055	(48)	**$4,949,053**	$7,160,888	(31)
$/boe	**3.45**	8.87	(61)	**3.63**	8.43	(57)
percent of sales	**9**	13	(31)	**10**	13	(23)

Revenue from crude oil, natural gas and associated natural gas liquids sales of $25,330,543 in the second quarter of 2015 was consistent with the $25,310,633 in the first quarter of 2015 and 22% lower than the $32,322,265 in the second quarter of 2014. Natural gas prices averaged $2.80/mcf and the combined oil and natural gas liquids prices averaged $55.47/bbl in the second quarter of 2015 as compared to $2.91/mcf and $44.81/bbl in the first quarter of 2015 and $4.37/mcf and $94.65/bbl in the second quarter of 2014, respectively.

Revenue remained flat during the second quarter of 2015, when compared to the first quarter of 2015, as a result of a 24% increase in crude oil and natural gas liquids pricing offset by a 19% decrease in crude oil and natural gas liquids production, a 5% decrease in natural gas production and a 4% decrease in natural gas prices.

The 22% decrease in revenue in the second quarter of 2015, compared to the second quarter of 2014, was primarily caused by a 41% decrease in crude oil and natural gas liquids pricing and a 36% decrease in natural gas pricing, partially offset by a 30% increase in crude oil and natural gas liquids production and a 41% increase in natural gas production.

The 11% decrease to revenue in the first half of 2015, compared to the first half of 2014, was primarily caused by a 47% decrease in crude oil and natural gas liquids pricing and a 38% decrease in natural gas pricing, partially offset by a 67% increase in crude oil and natural gas liquids production and a 51% increase in natural gas production.

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

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

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

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

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $81.18
Crude oil	500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	US $60.12
Crude oil	200 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	Cdn $75.00
Crude oil	200 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	US $62.00
Crude oil	2,500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $78.58
Crude oil	500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.52
Crude oil	1,900 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.23
Crude oil	700 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.86
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21
Crude oil	1,200 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $76.86
Crude oil	500 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $77.98
Natural gas	7,000 GJ/day	July 1, 2015 – September 30, 2015	AECO fixed price	Cdn $2.73
Natural gas	5,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.06
Natural gas	3,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.05

At June 30, 2015, the commodity contracts were fair valued with an asset of $1,133,291 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized loss of $7,337,619 recorded in earnings for the six months ended June 30, 2015.

At June 30, 2015, the Company held no physical commodity contracts.

Since June 30, 2015, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	Jan 1, 2016 – March 31, 2016	AECO fixed price	$3.00

Royalty expenses for the second quarter of 2015 were $3.45/boe or $2,192,889, representing 9% of revenue, compared to a royalty expense for the first quarter of 2015 of $3.78/boe or $2,756,164, representing 11% of revenue. The decrease in royalties as a percentage of revenue in the second quarter of 2015 as compared to the first quarter of 2015, was related to a lower than expected Company annual gas cost allowance adjustment.

The royalty expenses for the second quarter of 2014 were $8.87/boe or $4,201,055, representing 13% of revenue. The decrease in royalties as a percentage of revenue in the second quarter of 2015, as compared to the second quarter of 2014, was related to lower commodity prices and the impact of lower royalties on wells drilled in late 2014, partially offset by the higher royalty rates from the wells acquired by the Company on September 30, 2014 in the Wilson Creek Acquisition.

The royalty expenses for the first half of 2015 were $3.63/boe or $4,949,053, representing 10% of revenue, compared to royalty expense for the first half of 2014 of $8.43/boe or $7,160,888, representing 13% of revenue. The decrease in royalties as a percentage of revenue in the first half of 2015, as compared to the first half of 2014, was related to lower commodity prices and the impact of lower royalties on wells drilled in late 2014, partially offset by the higher royalty rates from the wells acquired by the Company on September 30, 2014 in the Wilson Creek Acquisition.

Although the Company expects royalty rates to remain lower in 2015 compared to those realized in 2014 due to lower commodity prices, it does expect royalty rates to be higher in the third quarter of 2015 from the second quarter due to the Alder Flats Acquisition.

Production Expenses

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Total production expenses	**$7,909,969**	$6,792,275	16	**$17,049,286**	$11,778,531	45
Total ($/boe)	**$12.43**	$14.35	(13)	**$12.50**	$13.86	(10)

Production expenses for the second quarter of 2015 were $12.43/boe compared to $12.55/boe incurred during the first quarter of 2015. The production expenses on a per boe basis decreased by $0.12/boe in the second quarter of 2015 as a result of the continuation of cost cutting measures in the Wilson Creek area implemented since closing of the Wilson Creek Acquisition in September 2014 and the completion of the Hatton oil battery, which resulted in higher production rates and reduced trucking costs.

On a dollar basis, overall costs decreased in the second quarter of 2015 by 13% to $7,909,969 from the $9,139,317 incurred during the first quarter of 2015. The decrease in total production costs resulted from the 14% decrease in production.

Total production expenses on a boe basis were $12.43/boe in the second quarter of 2015 compared to $14.35/boe during the second quarter of 2014. Production expenses for the three months ended June 30, 2015 increased by 16% to $7,909,969, compared to $6,792,275 in the same period in 2014. The decrease in total production costs, on a per boe basis, resulted from the acquisition of the lower per unit cost Wilson Creek properties. On a dollar basis, overall costs increased as a result of a 34% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

Total production expenses on a boe basis were $12.50/boe in the first half of 2015 compared to $13.86/boe during the same period in 2014. Production expenses for the six months ended June 30, 2015 increased by 45% to $17,049,286, compared to $11,778,531 in the same period in 2014. The decrease in total production costs, on a per boe basis, resulted from the acquisition of the lower per unit cost Wilson Creek properties. On a dollar basis, overall costs increased as a result of a 61% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

Operating Netback

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2015**	2014	% change	**2015**	2014	% change
Average realized sales	**39.82**	68.27	(42)	**37.11**	66.86	(44)
Royalty expenses	**(3.45)**	(8.87)	(61)	**(3.63)**	(8.43)	(57)
Production expenses	**(12.43)**	(14.35)	(13)	**(12.50)**	(13.86)	(10)
Operating field netback	**23.94**	45.05	(47)	**20.98**	44.57	(53)
Realized commodity hedging gain (loss)	**3.23**	(3.58)	190	**4.18**	(3.53)	(218)
Operating netback	**27.17**	41.47	(34)	**25.16**	41.04	(39)

The operating netback for the second quarter of 2015 increased by 16% to $27.17/boe compared to $23.42/boe during the first quarter of 2015. The increase was the result of a 24% increase in oil and natural gas liquids prices ($55.47/bbl versus $44.81/bbl) and a 9% decrease in royalty expense per boe ($3.45/boe versus $3.78/boe), partially offset by a 4% decrease in natural gas prices ($2.80/mcf versus $2.91/mcf) and a realized hedging gain of $3.23/boe during the second quarter of 2015, compared to a realized hedging gain of $5.00/boe during the first quarter 2015.

The operating netback for the second quarter of 2015 decreased by 34% to $27.17/boe compared to $41.47/boe during the second quarter of 2014. The decrease was the result of a 41% decrease in oil and natural gas liquids prices ($55.47/bbl versus $94.65/bbl) and a 36% decrease in natural gas prices ($2.80/mcf versus $4.37/mcf), partially offset by a decrease of 61% in royalty expense per boe ($3.45/boe versus $8.87/boe), a realized hedging gain of $3.23/boe during the second quarter 2015 compared to a $3.58/boe realized hedging loss during the second quarter of 2014 and a 13% decrease in operating expense per boe ($12.43/boe versus $14.35/boe).

The operating netback for the first half of 2015 decreased by 39% to $25.16/boe compared to $41.04/boe during the first half of 2014. The decrease was the result of a 47% decrease in oil and natural gas liquids prices ($49.62/bbl versus $94.05/bbl) and a 38% decrease in natural gas prices ($2.86/mcf versus $4.64/mcf), partially offset by a decrease of 57% in royalty expense per boe ($3.63/boe versus $8.43/boe), a realized hedging gain of $4.18/boe during the second quarter 2015 compared to a $3.53/boe realized hedging loss during the second quarter of 2014 and a 10% decrease in operating expense per boe ($12.50/boe versus $13.86/boe).

General and Administrative Expenses

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Gross costs	**$2,193,236**	$1,918,962	14	**$4,663,757**	$3,626,905	29
Capitalized costs and recoveries	**(540,550)**	(409,618)	32	**(938,380)**	(794,777)	18
General and administrative costs	**$1,652,686**	$1,509,344	9	**$3,725,377**	$2,832,128	32
Total ($/boe)	**$2.60**	$3.19	(18)	**$2.73**	$3.33	(18)

General and administrative expenses for the second quarter of 2015 were $2.60/boe on costs of $1,652,686 compared to $2.85/boe on costs of $2,072,691 in the first quarter of 2015. The lower costs in the second quarter of 2015 were related to the impact of cost cutting measures initiated during the first quarter. The decrease in the cost per boe in the second quarter of 2015 from the first quarter of 2015 was the result of the impact of cost cutting measures initiated during the first quarter.

General and administrative expenses for the second quarter of 2014 were $3.19/boe on costs of $1,509,344. While overall costs increased 9% in the second quarter of 2015 due to Tamarack's expanded operations, the costs per unit decreased 18% due to a 34% increase in production.

General and administrative expenses for the first half of 2015 were $2.73/boe on costs of $3,725,377 compared to 3.33/boe on costs of $2,832,128 during the same period in 2014. While overall costs increased to $3,725,377 in the first half of 2015 due to Tamarack's expanded operations, the costs per unit decreased 18% in the first half of 2015 due to a 61% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses of $857,833 and $1,597,346, relating to the preferred shares, stock options and restricted share awards for the three and six months ended June 30, 2015, were higher compared to $582,404 and $1,120,206 for the same periods in 2014, due to the issuance of new options and restrictive share awards in the third quarter of 2014. Stock-based compensation expense is calculated based on graded vesting periods that are front end loaded.

The Company capitalized $380,804 and $794,196 of stock-based compensation expenses relating to exploration and development activities for the three and six months ended June 30, 2015, compared to capitalizing $268,826 and $498,436 for the same periods in 2014.

For the three and six months ended June 30, 2014 the Company issued 57,000 options at a weighted average exercise price of $4.18 per share and issued 25,000 restricted stock units.

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

Interest

Interest expense was $1,415,436 and $2,656,970 for the three and six months ended June 30, 2015, compared to $333,703 and $816,392 for the same periods in 2014. The Company has drawn $88,500,000 on its revolving credit facility at June 30, 2015, compared to $43,734,511 drawn on its line at June 30, 2014. The increase in the average amount drawn quarter-over-quarter resulted in an increase in interest expense.

Depletion, Depreciation, Amortization and Accretion

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

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Depletion and depreciation	**$13,336,610**	$9,722,566	37	**$29,263,822**	$17,025,140	72
Amortization of undeveloped leases	**190,590**	831,797	(77)	**395,517**	1,564,330	(75)
Accretion	**183,922**	150,035	23	**441,022**	295,108	49
Total	**$13,711,122**	$10,704,398	28	**$30,100,361**	$18,884,578	59
Depletion and depreciation ($/boe)	**$20.96**	$20.54	2	**$21.45**	$20.03	7
Amortization ($/boe)	**0.30**	1.76	(83)	**0.29**	1.84	(84)
Accretion ($/boe)	**0.29**	0.32	(9)	**0.32**	0.35	(9)
Total ($/boe)	**$21.55**	$22.62	(5)	**$22.06**	$22.22	–

Depletion, depreciation, amortization, and accretion expense on a boe basis for the second quarter of 2015 was 4% lower at $21.55/boe, compared to $22.50/boe during the first quarter of 2015. Depletion, depreciation, amortization and accretion expense for the second quarter of 2015 was $13,711,122, compared to $16,389,239 during the first quarter of 2015. The 16% decrease in total depletion, depreciation, amortization, and accretion expense was the result of the 14% decrease in production.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the second quarter of 2015 was $21.55/boe, compared to $22.62/boe during the second quarter of 2014. Depletion, depreciation, amortization, and accretion expense for the second quarter of 2015 was $13,711,122, compared to $10,704,398 during the second quarter of 2014. The second quarter 2015 decrease in depletion, depreciation, amortization, and accretion expense rate as compared to the second quarter of 2014 was a result of the lower amortization rate partially offset the increased percentage of overall production related to the higher cost Cardium, Viking and heavy oil properties. The 31% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 34% increase in production, partially offset by lower per unit depletion, depreciation and accretion expense on a boe basis.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the first half of 2015 was $22.06/boe, compared to $22.22/boe during the first half of 2014. Depletion, depreciation, amortization, and accretion expense for the first half of 2015 was $30,100,361, compared to $18,884,578 during the first half of 2014. The 59% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 61% increase in production.

Income Taxes

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

For the three and six months ended June 30, 2015, a deferred income tax recovery of $3,634,876 and

$5,135,581 was recognized, compared to a deferred income tax expense of $1,941,647 and $2,717,808 for the same periods in 2014. There was a deferred tax recovery during the three and six months ended June 30, 2015 due to a loss before taxes, while in the same periods of 2014 a deferred tax expense was recorded due to income before taxes being recognized.

On June 29, 2015, the general corporate income tax rate for Alberta increased to 12% from 10% effective July 1, 2015. As a result of the changes, the Company's deferred income tax asset increased by $2.2 million at June 30, 2015.

Funds from Operations and Net Income

Funds from operations during the second quarter of 2015 were $13,185,630 ($0.16 per share basic and diluted) compared to funds from operations of $13,742,786 ($0.18 per share basic and diluted) for the first quarter of 2015. The decrease in funds from operations is primarily the result of a 14% decrease in production, the $1,031,517 in transactions costs associated with the Alder Flats Acquisition and a lower realized hedging gain, partially offset by the 24% increase in crude oil and natural gas liquids pricing and lower royalty expense.

Funds from operations during the three months ended June 30, 2015 were $13,185,630 ($0.16 per share basic and diluted), compared to funds from operations of $17,789,622 ($0.29 per share basic and diluted) for the same period in 2014. The decrease in funds from operations was primarily the result of the 41% decrease in crude oil and natural gas liquids pricing, a 36% decrease in natural gas pricing, higher interest expense and higher production expenses related to the increased production, partially offset by a realized hedging gain in the second quarter of 2015 compared to a realized hedging loss in the second quarter of 2014 and a 34% increase in production and lower royalty expense.

Funds from operations during the first half of 2015 were $26,928,416 ($0.33 per share basic and diluted), compared to funds from operations of $31,234,785 ($0.55 per share basic and $0.54 per share diluted) for the same period in 2014. The decrease in funds from operations was primarily the result of the 47% decrease in crude oil and natural gas liquids pricing, a 38% decrease in natural gas pricing, higher interest expense and higher production expenses related to the increased production, partially offset by a realized hedging gain in the first half of 2015 compared to a realized hedging loss in the first half of 2014 and a 61% increase in production and lower royalty expense.

The Company had a net loss of $2,141,787 ($0.03 per share basic and diluted) during the three months ended June 30, 2015, compared to a net loss of $5,241,630 ($0.07 per share basic and diluted) for the first quarter of 2015. The Company recorded a lower net loss for the three months ended June 30, 2015 as compared to the first quarter of 2015 as a result of lower depletion, depreciation, amortization, and accretion expense and lower production costs due to a 14% decrease in production, partially offset by a higher unrealized loss on financial instruments taken in the second quarter of 2015 as compared to the first quarter of 2015, transactions costs associated with the Alder Flats Acquisition and a 24% increase in crude oil and natural gas liquids pricing.

The Company had net loss of $2,141,787 ($0.03 per share basic and diluted) during the three months ended June 30, 2015, compared to net income of $5,242,572 ($0.09 per share basic and $0.08 per share diluted) for the same period in 2014. The Company recorded a net loss for the three months ended June 30, 2015 as compared to net income from the same period in 2014 as a result of 41% decrease in crude oil and natural gas liquids pricing, a 36% decrease in natural gas pricing, a unrealized hedging loss in the second quarter of 2015 compared to a unrealized hedging gain in the second quarter of 2014, a deferred income tax recovery in the second quarter of 2015 as compared to a deferred tax expense in the second quarter of 2014, higher depletion, depreciation, amortization, and accretion expense, transactions costs associated with the Alder Flats Acquisition and higher production expenses related to the increased production, partially offset by a realized hedging gain in the second quarter of 2015 compared to a realized hedging loss in the second quarter of 2014 and a 34% increase in production.

The Company had net loss of $7,383,417 ($0.09 per share basic and diluted) during the six months ended June 30, 2015, compared to net income of $7,033,253 ($0.12 per share basic and diluted) for the same period in 2014. The Company recorded a net loss for the six months ended June 30, 2015 as compared to the same period in 2014 as a result of 47% decrease in crude oil and natural gas liquids pricing, a 38% decrease in natural gas pricing, a higher unrealized hedging loss in the first half of 2015 compared to the first half of 2014, a deferred income tax recovery in the first half of 2015 as compared to a deferred tax expense in the first half of 2014, higher depletion, depreciation, amortization and accretion expense, transactions costs associated with the Alder Flats Acquisition and higher production expenses related to the increased production, partially offset by a realized hedging gain in the first half of 2015 compared to a realized hedging loss in the first half of 2014 and a 61% increase in production.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended June 30			Six months ended June 30,		
	2015	2014	% change	**2015**	2014	% change
Land	335,922	$458,687	(27)	**$411,544**	$2,722,608	(85)
Geological and geophysical	(22,997)	192,212	(112)	**7,509**	291,437	(97)
Drilling and completion	8,205,965	32,422,373	(75)	**12,814,694**	53,092,240	(76)
Equipment and facilities	5,543,683	7,279,260	(24)	**7,510,352**	9,308,399	(19)
Capitalized G&A	317,181	356,961	(11)	**484,412**	685,684	(29)
Office equipment	1,485	32,776	(95)	**1,485**	37,800	(96)
Total capital expenditures	**$14,381,239**	$40,742,269	(65)	**$21,229,996**	$66,138,168	(68)
Property acquisition	**54,173,650**	–	–	**54,173,650**	–	–
Proceeds from disposal of property, plant and equipment	**(135,000)**	–	–	**(1,955,583)**	(383,853)	409
Total net capital expenditures	**$68,419,889**	$40,742,269	68	**$73,448,063**	$65,754,315	12

During the second quarter of 2015, the Company completed 4 (2.4 net) previously drilled horizontal Cardium wells, drilled, completed and equipped 2 (2.0 net) horizontal Cardium wells and spudded 1 (1.0 net) horizontal Cardium oil well all in the Wilson Creek area. On May 14, 2015, the Company announced an increase to its planned 2015 capital expenditure budget to between $76 and $86 million (excluding the cost of the Alder Flats Acquisition) from $47 million. The increase was as a result of improved economics in light of the 15% increase in oil and NGL prices to $55.47/bbl from $48.33/bbl in the first quarter of 2015 and the realized 20% reduction in service costs that contributed to improved capital efficiencies. On July 29, 2015, the Company reduced its 2015 capital expenditure budget by 6.5%-11.6% to between $71 and $76 million in response to the recent decrease in crude oil prices. Tamarack is prepared to adjust its capital budget to account for changes in commodity prices as the year progresses in order to preserve capital and generate an expedited return on future capital deployed.

2015 Drilling Summary (including wells spudded by June 30, 2015)		
	Gross	Net
Cardium	5.0	5.0
	5.0	5.0

For the three and six months ended June 30, 2015, the Company disposed of its interest in certain oil and gas properties for $135,000. There was no production associated with these properties. The Company will continue to pursue disposition of non-core assets.

The Company's net undeveloped acreage was 201,075 acres at the end of the second quarter of 2015.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $97,280,149 at June 30, 2015. Tamarack's net debt at June 30, 2014 was $59,489,653 and at December 31, 2014 was $129,798,673. During the first half of 2015, the Company reduced net debt by $32,518,524 improving financial flexibility by spending less on capital expenditures than realized funds from operations and the financing that closed in June 2015. Tamarack's net debt at June 30, 2015 to annualized funds from operations in the second quarter of 2015 was 1.9 times, compared to 0.8 times at June 30, 2014 and 1.7 times at December 31, 2014.

On June 3, 2015, the Company completed a bought deal financing by issuing 17,197,000 common shares at $3.78 per share for total gross proceeds of $65,004,660. Certain officers, directors and employees acquired 18,600 common shares for gross proceeds of $70,308. On June 10, 2015, the over-allotment option was exercised, resulting in the issuance of 2,579,550 common shares at $3.78 per share for total gross proceeds of $9,750,699.

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

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

At June 30, 2015 and August 12, 2015, there were 99,933,725 common shares, 1,110,584 preferred shares, 4,040,551 options and 431,500 restricted share awards outstanding. At December 31, 2014 there were 77,928,466 common shares, 1,176,000 preferred shares, 4,147,386 options and 406,500 restricted share awards outstanding. The Company had 84,493,217 and 81,228,976 weighted average basic common shares outstanding during the three and six months ended June 30, 2015.

At June 30, 2015, the Company had a revolving credit facility in the amount of $140,000,000 and a $10,000,000 operating facility (collectively the "Facility").

Subsequent to June 30, 2015, based on the completion of its annual review, the Company's lenders have increased the Facility to $165 million. The $165 million is made up of a revolving credit facility in the amount of $155 million and a $10 million operating facility. The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 27, 2017. The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 1.0%, to a high of the bank’s prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the credit facilities. The Facility has been secured by a $300 million supplemental debenture with a floating charge over all assets. As the available lending limits of the facilities are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next scheduled mid-year review is to take place during the fourth quarter of 2015.

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

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

2015 Guidance

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

The 2015 capital budget and guidance was announced as follows:

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

On July 29, 2015, as a result of the 15% decrease in oil prices, Tamarack announced a reduction in capital spending for the remainder of 2015. The Company reduced its capital program by 6.5% to 11.6% to between $71 and $76 million, from $76 to $86 million. This resulting capital program was based on a WTI price of $45.00/bbl, Edmonton Par price of $53.50/bbl, an AECO price of $2.75/GJ and a $0.77 Canadian dollar for the second half of 2015.

The current 2015 capital budget and guidance is as follows:

- $71-$81 million capital program in addition to the $55 million Alder Flats Acquisition (total $125-$130 million)
- Production to average between 8,000-8,200 boe/d (approximately 55-60% oil & NGLs)
- Exit production rate between 9,200-9,500 boe/d (approximately 55-60% oil & NGLs)
- Exit debt to Q4/15 annualized funds from operations is expected to be 1.75 times based on the above commodity assumptions

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

Commitments

In the normal course of business, the Company has obligations representing contracts and other commitments with an estimated payment of $358,949 for 2015, $418,178 for 2016 and $99,594 for 2017. These obligations are related to office lease commitments.

On June 3, 2015, the Company issued 2,186,800 flow-through common shares related to Canadian development expenditures for gross proceeds of $9,075,220. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $9,075,220 of qualifying oil and natural gas expenditures effective December 31, 2015. As of June 30, 2015 the Company has not incurred any of these expenditures.

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

In conjunction with the Wilson Creek Acquisition, Tamarack has a take or pay obligation on a sales pipeline owned by a mid-stream company of $1.43/bbl on a minimum of 1,887 bbls/d of crude oil or condensate. The remaining term is 40 months. During the six months ended June 30, 2015, the Company delivered an average of 1,653 bbls/d of liquids through this pipeline.

The Company is required to pay a rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four operated facilities.

The following table summarizes the Company’s commitments at June 30, 2015:

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease	358,949	418,178	99,594	–	–	–	–	–
Take or pay commitments	496,800	988,200	985,500	985,500	–	–	–	–
Drilling commitments	12,760,000	9,240,000	9,000,000	–	–	–	–	–
Rental fee	2,806,594	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	1,871,063
Total	16,422,343	14,388,503	13,827,219	4,727,625	3,742,125	3,742,125	3,742,125	1,871,063

Non–IFRS and Additional IFRS Measures

This document contains “funds from operations”, which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds generated from operations as a key measure to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment. This document also contains the terms “net debt” and “netbacks”, which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses net debt (bank debt net of working capital and excluding fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers corporate netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a boe basis by deducting royalties and operating costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts.

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

A summary of this reconciliation is presented as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	**2015**	2014
Cash provided by operating activities	**$8,520,433**	$12,021,360	**$25,391,639**	$27,916,229
Abandonment expenditures	**88,253**	235,991	**154,807**	275,168
Changes in non-cash working capital	**4,576,944**	5,532,271	**1,381,970**	3,043,388
Funds from operations	**$13,185,630**	$17,789,622	**$26,928,416**	$31,234,785
Funds from operation per share -basic	**$ 0.16**	$ 0.29	**$ 0.33**	$ 0.55
Funds from operation per share -diluted	**$ 0.16**	$ 0.29	**$ 0.33**	$ 0.54

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

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

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

	June 30, 2015	December 31, 2014
Cash and cash equivalents	$3,428,442	$830,104
Accounts receivables	15,738,153	20,370,676
Prepaid expenses	822,349	810,983
Accounts payable and accrued liabilities	(28,769,093)	(51,610,436)
Bank debt	(88,500,000)	(100,200,000)
Net debt	$(97,280,149)	$(129,798,673)

Selected Quarterly Information

Three months ended	**Jun. 30, 2015**	**Mar. 31, 2015**	**Dec. 31, 2014**	**Sep. 30, 2014**	**Jun. 30, 2014**	**Mar. 31, 2014**	**Dec. 31, 2013**	**Sep. 30, 2013**
Sales volumes								
Natural gas *(mcf/d)*	**16,972**	17,864	17,518	12,462	12,033	11,093	10,349	7,767
Oil and NGLs *(bbls/d)*	**4,163**	5,115	4,761	3,688	3,197	2,333	2,611	1,867
Average boe/d *(6:1)*	**6,992**	8,092	7,681	5,765	5,203	4,182	4,336	3,162
Product prices								
Natural gas *($/mcf)*	**2.80**	2.91	3.91	4.13	4.37	4.93	3.72	2.99
Oil and NGLs *($/bbl)*	**55.47**	48.33	62.87	90.19	94.65	93.23	77.78	98.65
Oil equivalent *($/boe)*	**39.82**	34.75	47.89	66.62	68.27	65.09	55.72	65.60
(000s, except per share amounts)								
Financial results								
Gross revenues	**25,331**	25,311	33,839	35,333	32,322	24,498	22,224	19,082
Funds from operations	**13,186**	13,743	19,128	15,809	17,790	13,445	10,505	10,260
Per share – basic	**0.16**	0.18	0.25	0.26	0.29	0.26	0.24	0.35
Per share – diluted	**0.16**	0.18	0.25	0.26	0.29	0.25	0.23	0.34
Net income (loss)	**(2,142)**	(5,242)	(38,991)	6,791	5,243	1,791	10,855	3,721
Per share – basic	**(0.03)**	(0.07)	(0.50)	0.11	0.09	0.03	0.37	0.13
Per share – diluted	**(0.03)**	(0.07)	(0.50)	0.11	0.08	0.03	0.37	0.13
Additions to property and equipment, net of proceeds	**68,420**	5,028	26,774	196,375	40,742	25,012	22,010	10,691
Net property acquisitions	**–**	–	–	166,057	–	–	–	–
Corporate acquisitions	–	–	–	–	–	–	57,135	–
Total assets	**561,977**	482,227	497,578	525,003	319,065	288,608	269,707	170,610
Working capital (deficiency)[1]	**(97,280)**	(121,159)	(129,799)	(121,684)	(59,490)	(37,130)	(81,764)	(57,088)
Bank debt[2]	**88,500**	112,951	100,200	100,275	43,735	17,494	71,796	50,876
Decommissioning obligations	**64,883**	(45,340)	41,357	36,732	20,956	20,484	19,802	12,795
Deferred income tax (asset)	**(33,647)**	(28,802)	(27,299)	(16,870)	(17,743)	(19,681)	(19,467)	(8,717)

(1) Excluding fair value of financial instruments

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

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

- The volatility in commodity prices and the effect this has had on revenue and net income (loss).

- The volatility in forward price curves affects the mark-to-market calculation, which results in swings in earnings.
- The recorded impairment charges on the Company's oil and natural gas related CGUs due to falling oil and gas prices in the amount of $56,290,000 in the fourth quarter of 2014.
- On September 30, 2014, the Company acquired 100% of a major's interests in the Wilson Creek area of Alberta; in 2014 this acquisition added $5,551,131 to oil and natural gas revenue and contributed $402,656 to net income.
- Oil volumes have continued to grow due to successful drilling at Lochend, Garrington, Greater Pembina area and Redwater, and from the Wilson Creek Acquisition and the acquisition of Sure Energy Inc. on October 9, 2013 (the "Sure Acquisition"). At the same time, the oil and natural gas liquids weighting has increased from 59% of total production in the second quarter of 2013 to 60% in the second quarter of 2015.
- On August 19, 2013, the Company entered into a farm-in agreement with an industry major to earn a 70% working interest in up to 113 net sections of prospective Cardium lands directly offsetting proven ongoing development projects in the greater Pembina area.
- In 2013, the Sure Acquisition added $4,214,745 to oil and natural gas revenue and contributed $239,547 to net income.
- The Company recorded a $10,053,750 gain on the Sure Acquisition for Q4 2013 as the fair value paid was less than the fair value of the assets acquired.
- The Company recorded $1,031,517 in transaction costs in the second quarter of 2015 related the Alder Flats Acquisition, $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition and $1,645,116 in transaction costs in the fourth quarter of 2013 related to the Sure Acquisition.

Critical Accounting Estimates

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

(a) **Oil and natural gas reserves** – Oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Natural Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

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

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

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

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

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

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

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

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

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

Business Risks

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

Financial Risks

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

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

Operational Risks

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

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

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

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

Regulatory Risks

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

The Alberta government recently announced plans to conduct a royalty review which could impact the amount of royalties payable in the future.

Forward Looking Statements

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

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

- Estimated production rates in 2015.
- Adjustments to the capital budget to account for commodity price changes.
- Future operating costs on a boe basis.
- Tamarack's primary focus areas for production growth.
- Tamarack's focus on reducing capital costs.
- Future drilling plans.
- Deferred tax liabilities.
- The interest rates under Tamarack's credit facilities.

- Future capital expenditures and capital program funding.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas weighting in 2015.
- Expectations as to royalty rates in 2015.
- The ability of the Company to take advantage of opportunities that may arise due to commodity price volatility.
- Disposition of non-core assets.

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

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

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

- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;

- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's revised Annual Information Form for the year ended December 31, 2014, which may be accessed on Tamarack's SEDAR profile at www.sedar.com.

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)

	June 30, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$3,428,442	$830,104
Accounts receivable	15,738,153	20,370,676
Prepaid expenses and deposits	822,349	810,983
Fair value of financial instruments (note 3)	1,133,291	8,470,910
	21,122,235	30,482,673
Property, plant and equipment (note 5)	503,538,379	435,328,116
Exploration and evaluation assets (note 6)	3,669,303	4,468,823
Deferred tax asset	33,647,117	27,298,825
	$561,977,034	$497,578,437
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$28,769,093	$51,610,436
Bank debt (note 11)	88,500,000	100,200,000
Decommissioning obligations (note 7)	64,882,658	41,356,532
Deferred flow-through share premium	809,116	–
Shareholders' equity:		
Share capital (note 9)	415,931,141	336,086,662
Contributed surplus	15,074,994	12,931,358
Deficit	(51,989,968)	(44,606,551)
	379,016,167	304,411,469
Commitments and contingencies (note 13)		
	$561,977,034	$497,578,437

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (loss) Comprehensive Income (loss)
For the three and six months ended June 30, 2015 and 2014
(unaudited)

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2014	2015	2014
Revenue:				
Oil and natural gas	$25,330,543	$32,322,265	$50,641,176	$56,820,520
Royalties	(2,192,889)	(4,201,055)	(4,949,053)	(7,160,888)
Realized gain (loss) on financial instruments (note 3)	2,057,584	(1,696,266)	5,699,443	(2,997,796)
Unrealized gain (loss) on financial instruments (note 3)	(4,528,338)	681,399	(7,337,619)	(377,056)
	20,666,900	27,106,343	44,053,947	46,284,780
Expenses:				
Production	7,909,969	6,792,275	17,049,286	11,778,531
General and administration	1,652,686	1,509,344	3,725,377	2,832,128
Transaction costs	1,031,517	–	1,031,517	–
Stock-based compensation (note 12)	857,833	582,404	1,597,346	1,120,206
Finance	1,599,358	483,738	3,097,992	1,111,500
Depletion, depreciation and amortization	13,527,200	10,554,363	29,659,339	18,589,470
Gain on disposition of property, plant and equipment (note 5)	(135,000)	–	412,088	1,101,884
	26,443,563	19,922,124	56,572,945	36,533,719
Income (loss) before taxes	(5,776,663)	7,184,219	(12,518,998)	9,751,061
Deferred income tax recovery (expense)	3,634,876	(1,941,647)	5,135,581	(2,717,808)
Net Income (loss) and comprehensive income (loss)	$(2,141,787)	$5,242,572	$(7,383,417)	$7,033,253
Net income (loss) per share (note 10):				
Basic	$(0.03)	$ 0.09	$(0.09)	$ 0.12
Diluted	$(0.03)	$ 0.08	$(0.09)	$ 0.12

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Equity
(unaudited)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2014	46,168,718	$157,974,725	$9,487,596	$(19,439,190)	148,023,131
Issue of common shares	30,479,748	176,404,941	–	–	176,404,941
Issue of flow-through shares	1,280,000	10,048,000			10,048,000
Share issue costs, net of tax of $2,769,148	–	(8,307,445)	–	–	(8,307,445)
Transfer on exercise of stock options and preferred shares	–	862,441	(862,441)	–	–
Flow-through share premium		(896,000)			(896,000)
Stock-based compensation	–	–	4,306,203	–	4,306,203
Net loss	–	–	–	(25,167,361)	(25,167,361)
Balance at December 31, 2014	77,928,466	336,086,662	12,931,358	(44,606,551)	304,411,469
Issue of common shares	19,818,459	74,860,360	–	–	74,860,360
Issue of flow-through shares	2,186,800	9,075,220			9,075,220
Share issue costs, net of tax of $1,212,711	–	(3,529,891)	–	–	(3,529,891)
Transfer on exercise of stock options and preferred shares	–	247,906	(247,906)	–	–
Flow-through share premium	–	(809,116)	–	–	(809,116)
Stock-based compensation	–	–	2,391,542	–	2,391,542
Net loss	–	–	–	(7,383,417)	(7,383,417)
Balance at June 30, 2015	99,933,725	$415,931,141	$15,074,994	$(51,989,968)	$379,016,167

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2014	46,168,718	$157,974,725	$9,487,596	$(19,439,190)	$148,023,131
Issue of common shares	14,294,249	61,045,405	–	–	61,045,405
Share issue costs, net of tax of $994,051	–	(2,982,154)	–	–	(2,982,154)
Transfer on exercise of stock options and preferred shares	–	699,645	(699,645)	–	–
Stock-based compensation	–	–	1,618,642	–	1,618,642
Net income	–	–	–	7,033,253	7,033,253
Balance at June 30, 2014	60,462,967	$216,737,621	$10,406,593	$(12,405,937)	$214,738,277

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

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

	Three Months ended June 30,		Six Months ended June 30,	
	2015	2014	2015	2014
Cash provided by (used in):				
Operating:				
Net income (loss)	$(2,141,787)	$5,242,572	$(7,383,417)	$7,033,253
Items not involving cash:				
Depletion, depreciation and amortization	13,527,200	10,554,363	29,659,339	18,589,470
Stock-based compensation	857,833	582,404	1,597,346	1,120,206
Loss (gain) on disposition of property, plant and equipment	(135,000)	–	412,088	1,101,884
Accretion expense on decommissioning obligations	183,922	150,035	441,022	295,108
Unrealized (gain) loss on financial instruments	4,528,338	(681,399)	7,337,619	377,056
Deferred income tax expense (recovery)	(3,634,876)	1,941,647	(5,135,581)	2,717,808
Funds from operations	13,185,630	17,789,622	26,928,416	31,234,785
Abandonment expenditures (note 7)	(88,253)	(235,991)	(154,807)	(275,168)
Changes in non-cash working capital (note 8)	(3,767,510)	(5,532,271)	(572,536)	(3,043,388)
Cash provided by operating activities	9,329,867	12,021,360	26,201,073	27,916,229
Financing:				
Change in bank debt	(24,451,205)	26,240,983	(11,700,000)	(28,061,434)
Proceeds from issuance of shares	83,935,580	845,405	83,935,580	61,045,405
Share issue costs	(4,734,202)	(16,124)	(4,742,602)	(3,976,205)
Cash provided by financing activities	54,750,173	27,070,264	67,492,978	29,007,766
Investing:				
Property, plant and equipment additions	(13,880,319)	(24,292,414)	(20,358,009)	(44,282,496)
Exploration and evaluation additions	(500,920)	(16,449,855)	(871,987)	(21,855,672)
Acquisitions	(54,983,084)	–	(54,983,084)	–
Proceeds from disposal of property, plant and equipment	135,000	–	1,955,583	383,853
Changes in non-cash working capital (note 8)	8,577,725	1,650,645	(16,838,216)	8,830,320
Cash used in investing activities	(60,651,598)	(39,091,624)	(91,095,713)	(56,923,995)
Change in cash and cash equivalents	3,428,442	–	2,598,338	–
Cash and cash equivalents, beginning of period	–	–	830,104	–
Cash and cash equivalents, end of period	$3,428,442	$ –	$3,428,442	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

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

Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. The address of its head office is currently 3100, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7.

2. Basis of preparation:

(a) Statement of compliance:

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

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

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on August 12, 2015.

3. Commodity contracts:

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

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

3. Commodity contracts (continued):

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

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

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	1,500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $81.18	$868,510
Crude oil	500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	US $60.12	$12,470
Crude oil	200 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	Cdn $75.00	($1,634)
Crude oil	200 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	US $62.00	$13,494
Crude oil	2,500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $78.58	$556,223
Crude oil	500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.52	($19,209)
Crude oil	1,900 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.23	($133,925)
Crude oil	700 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.86	($50,536)
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21	($291,999)
Crude oil	1,200 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $76.86	($120,812)
Crude oil	500 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $77.98	($23,052)
Natural gas	7,000 GJ/day	July 1, 2015 – September 30, 2015	AECO fixed price	Cdn $2.73	$146,978
Natural gas	5,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.06	$135,547
Natural gas	3,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.05	$41,236
					$1,133,291

At June 30, 2015, the commodity contracts were fair valued with an asset of $1,133,291 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized loss of $7,337,619 recorded in earnings for the six months ended June 30, 2015.

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement the realized benefit or loss is recognized in oil and natural gas revenue. At June 30, 2015, the Company held no physical commodity contracts.

3. Commodity contracts (continued):

Since June 30, 2015, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.00

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

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

Gross Amounts	**June 30, 2015**	December 31, 2014
Risk management contracts		
Current asset	**$2,307,795**	$8,470,910
Current liability	**(1,174,504)**	–
Balance, end of the period	**$1,133,291**	$8,470,910

4. Property Acquisition:

In June 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta for an aggregate cash purchase price of $55.0 million, prior to closing adjustments. The purpose of this acquisition was to increase the Company's exposure to the Cardium oil play. The operations from the acquisition have been included in the results of the Company commencing in June 2015. The Company incurred transaction costs of $1,031,517, which were expensed through the statement of income and comprehensive income.

The allocation of the purchase price is as follows:

Cash Consideration:		
Total consideration	$	54,983,084
Net Assets Acquired:		
Prepaid expense	$	809,434
Property, plant and equipment		62,105,520
Decommissioning obligations		(7,931,870)
Net assets	$	54,983,084

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

4. Property Acquisition (continued):

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

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

Period ended June 30, 2015	As stated	Alder Flats Prior to acquisition	Pro Forma
Oil and natural gas revenue	$50,641,176	$7,855,791	$58,496,967
Net income	(7,649,273)	(1,568,330)	(9,217,603)

5. Property, plant and equipment:

	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2014	$275,426,366	$276,670	$275,703,036
Property acquisition	173,606,620	–	173,606,620
Cash additions	59,854,564	55,814	59,910,378
Decommissioning costs	14,499,800	–	14,499,800
Stock-based compensation	1,327,975	–	1,327,975
Transfer from exploration and evaluation assets	97,227,381	–	97,227,381
Disposals	(36,448,859)	–	(36,448,859)
Balance at December 31, 2014	585,493,847	332,484	585,826,331
Property acquisition	62,105,520	–	62,105,520
Cash additions	20,356,524	1,485	20,358,009
Decommissioning costs	15,371,177	–	15,371,177
Stock-based compensation	794,196	–	794,196
Transfer from exploration and evaluation assets	1,275,990	–	1,275,990
Disposals	(2,562,187)	–	(2,562,187)
Balance at June 30, 2015	$682,835,067	$333,969	$683,169,036
Depletion, depreciation and impairment losses:			
Balance at January 1, 2014	$54,270,113	$121,163	$54,391,276
Depletion and depreciation	44,784,177	56,413	44,840,590
Transfer from exploration and evaluation assets	2,460,234	–	2,460,234
Disposals	(7,483,885)	–	(7,483,885)
Impairment loss	56,290,000	–	56,290,000
Balance at December 31, 2014	150,320,639	177,576	150,498,215
Depletion and depreciation	29,240,368	23,454	29,263,822
Disposals	(131,380)	–	(131,380)
Balance at June 30, 2015	$179,429,627	$201,030	$179,630,657

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2014	$435,173,208	$154,908	$435,328,116
At June 30, 2015	$503,405,440	$132,939	$503,538,379

For the six months ended June 30, 2015 the Company disposed of its interest in certain oil and gas properties for $1,955,583.

5. Property, plant and equipment (continued):

The calculation of depletion at June 30, 2015 includes estimated future development costs of $408,822,000 (December 31, 2014 – $374,258,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $26,338,000 (December 31, 2014 – $23,400,000).

6. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2014	$26,814,629
Additions	94,043,801
Transfer to property, plant and equipment	(97,227,381)
Balance at December 31, 2014	23,631,049
Additions	871,987
Transfer to property, plant and equipment	(1,275,990)
Balance at June 30, 2015	$23,227,046
Amortization and impairment:	
Balance at January 1, 2014	$15,158,239
Amortization	2,987,449
Exploration and evaluation impairment	3,476,772
Transfer to property, plant and equipment	(2,460,234)
Balance at December 31, 2014	19,162,226
Amortization	395,517
Balance at June 30, 2015	$ 19,557,743

	Total
Carrying amounts:	
At December 31, 2014	$4,468,823
At June 30, 2015	$3,669,303

Exploration and evaluation (E&E) assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period. For the year ended December 31, 2014 the Company recognized an impairment of $3,476,772 related to an exploratory oil play that would be uneconomic at current oil prices.

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 amount of cash flows required to settle its decommissioning obligations to be approximately $61.8 million at June 30, 2015 (December 31, 2014 – $43.0 million), which is expected to be incurred between 2015 and 2038. A risk-free rate of 1.8% (2014 – 2.5%) and an inflation rate of 2% (2014 – 2%) is used to calculate the fair value of the decommissioning obligations at June 30, 2015 as presented in the table below:

	June 30, 2015	December 31, 2014
Balance, beginning of the period	**$41,356,532**	$19,801,991
Liabilities incurred	**345,356**	3,504,114
Liabilities acquired	**7,931,870**	7,550,058
Change in estimates	**3,691,456**	3,224,957
Change in discount rate on acquisition	**11,334,365**	7,770,729
Expenditures	**(154,807)**	(678,886)
Liabilities disposed	**(63,136)**	(540,597)
Accretion	**441,022**	724,166
Balance, end of the period	**$64,882,658**	$41,356,532

The decommissioning obligations acquired in the Alder Flats Acquisition (note 4) were initially recognized using a fair value discount rate of 8%. They were subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

A change in estimate resulted from the decommissioning obligations being revalued using the risk-free rate of 1.8% as at March 31, 2015 a decrease from the risk-free rate of 2.5% used on December 31, 2014.

8. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	**2015**	2014
Source/(use of cash):				
Accounts receivable	**$(968,445)**	$(1,196,382)	**$4,632,523**	$(3,239,297)
Prepaid expenses and deposits	**(181,162)**	(184,200)	**(11,366)**	(146,978)
Accounts payable and accrued liabilities	**5,150,388**	(2,501,044)	**(22,841,343)**	9,173,207
Working capital acquired on acquisition	**809,434**	–	**(809,434)**	–
	$4,810,215	$(3,881,626)	**$(17,410,752)**	$5,786,932
Related to operating activities	**$(4,576,944)**	$(5,532,271)	**$(1,381,970)**	$(3,043,388)
Related to investing activities	**$8,577,725**	$1,650,645	**$(16,838,216)**	$8,830,320

9. Share capital:

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

On June 3, 2015, the Company completed a bought deal financing by issuing 17,197,000 common shares at $3.78 per share for total gross proceeds of $65,004,660. Certain officers, directors and employees acquired 18,600 common shares for gross proceeds of $70,308. On June 10, 2015, the over-allotment option was exercised resulting in the issuance of 2,579,550 common shares at $3.78 per share for total gross proceeds of $9,750,699.

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

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

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,	
	2015	2014	**2015**	2014
Net income (loss) for the period	**$(2,141,787)**	$5,242,572	**$(7,383,417)**	$7,033,253
Weighted average shares - basic	**84,493,217**	60,352,255	**81,228,976**	56,471,970
Weighted average shares - diluted	**84,493,217**	62,079,457	**81,228,976**	57,910,218
Net income (loss) per share-basic	**$(0.03)**	$ 0.09	**$(0.09)**	$ 0.12
Net income (loss) per share-diluted	**$(0.03)**	$ 0.08	**$(0.09)**	$ 0.12

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and six months ended June 30, 2015, 5,582,635 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive. For the three and six months ended June 30, 2014, 565,000 stock options and preferred shares were excluded from the diluted earnings per share as they were anti-dilutive.

11. Bank debt:

At June 30, 2015, the Company had a revolving credit facility in the amount of $140 million and a $10 million operating facility (collectively the “Facility”).

Subsequent to June 30, 2015, based on the completion of the annual bank review, the Company’s lenders have increased the Facility to $165 million.

11. Bank debt (continued):

The $165 million is made up of a revolving credit facility in the amount of $155 million and a $10 million operating facility. The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 27, 2017. The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 1.0%, to a high of the bank’s prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the credit facilities. The Facility has been secured by a $300 million supplemental debenture with a floating charge over all assets. As the available lending limits of the facilities are based on the bank’s interpretation of the Company’s reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next scheduled review is to take place during the fourth quarter of 2015.

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

At June 30, 2015, the Company had utilized the Facility in the amount of $88.5 million and the Company was compliant with its working capital ratio at 2.8 to 1.0.

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

12. Share-based payments:

(a) Preferred share plan:

As at June 30, 2015 there are 1,110,584 (December 31, 2014 – 1,176,000) common shares underlying preferred shares outstanding and exercisable with an exchange price of $3.12 per common share.

Under the terms of the Company’s preferred share plan, a cashless settlement alternative is available, whereby preferred share-holders can either (i) elect to receive shares by delivering cash to the Company in the amount of the preferred shares, or (ii) elect to receive a number of shares equivalent to the market value of the preferred share over the exercise price. For the period ended June 30, 2015 preferred share-holders exercised 65,416 preferred shares on a cashless settlement basis and received 12,742 common shares.

(b) Stock option plan:

Under the Company’s stock option and restricted share unit plan it may grant up to 9,993,373 options or restricted share units to its employees, directors and consultants of which 5,064,781 options, preferred shares and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of

12. Share-based payments (continued):

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 57,000 options granted during the period.

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

	Six months ended June 30, 2015	Year ended December 31, 2014
Risk free rate (%)	**0.69**	1.39
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**2.66**	3.57

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

	Number of options	Weighted average exercise price
Outstanding, January 1, 2014	3,164,551	$ 2.92
Granted	1,223,000	5.49
Exercised	(173,498)	2.57
Forfeited	(66,667)	2.39
Outstanding, December 31, 2014	4,147,386	$ 3.70
Granted	57,000	4.18
Exercised	(29,167)	3.60
Forfeited	(134,668)	3.25
Outstanding, June 30, 2015	**4,040,551**	**$ 3.74**

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

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price
$ 1.86 – 3.00	1,083,051	$2.12	2.2	722,035	$2.12
$ 3.01 – 5.00	2,491,500	$3.86	3.2	955,831	$3.94
$ 5.01 – 6.82	466,000	$6.82	4.1	–	–
$ 1.86 – 6.82	**4,040,551**	**$3.74**	**3.1**	**1,677,866**	**$3.16**

(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

12. Share-based payments (continued):

restricted stock unit plan, each restrictive share award entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant.

For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. The weighted average fair value of awards granted for the six month ended June 30, 2015 was $4.16 per share award. On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards at June 30, 2015:

	Number of awards
Outstanding, December 31, 2014	406,500
Granted	25,000
Outstanding, June 30, 2015	**431,500**

13. Commitments and contingencies:

(a) Commitments

In the normal course of business, the Company has obligations which represent contracts and other commitments with an estimated payment of $358,949 for 2015, $418,178 for 2016 and $99,594 for 2017. These obligations are related to office lease commitments.

On June 3, 2015, the Company issued 2,186,800 flow-through common shares related to Canadian development expenditures for gross proceeds of $9,075,220. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $9,075,220 of qualifying oil and natural gas expenditures effective December 31, 2015. As of June 30, 2015 the Company has not incurred any of these expenditures.

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

In conjunction with the Wilson Creek Acquisition, the Company is responsible for delivering a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 40 months.

The Company is required to pay a rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities.

13. Commitments and contingencies (continued):

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

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease	358,949	418,178	99,594	–	–	–	–	–
Take or pay commitments	496,800	988,200	985,500	985,500	–	–	–	–
Drilling commitments	12,760,000	9,240,000	9,000,000	–	–	–	–	–
Rental fee	2,806,594	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	3,742,125	1,871,063
Total	16,422,343	14,388,503	13,827,219	4,727,625	3,742,125	3,742,125	3,742,125	1,871,063

(b) Contingencies

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

CORPORATE INFORMATION

Directors

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

Dean Setoguchi[(1)(3)]

David Mackenzie[(1)(2)]

Jeff Boyce[(2)(3)]

Brian Schmidt

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

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Noralee Bradley
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Osler, Hoskin & Harcourt LLP

Auditor

KPMG LLP

Stock Exchange

TSX Venture Exchange

Stock symbol: TVE

Contact Information

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