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 months ended March 31, 2015 and 2014. This MD&A is dated and based on information available on May 12, 2015 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three months ended March 31, 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" located on pages 12 to 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 a Calgary-based oil and natural gas exploration and production company focused on delivering a superior rate of return on capital investment. Tamarack is 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. To date, Tamarack has established two core plays in Alberta: Cardium oil play in Lochend, Garrington and the greater Pembina area, including Wilson Creek and Alder Flats, and the shallow Viking oil play in Redwater and Westlock.

Production

	Three months ended March 31,		
	2015	2014	% change
Production			
Light oil (bbls/d)	**4,029**	2,103	92
Heavy oil (bbls/d)	**498**	83	500
Natural gas liquids (bbls/d)	**588**	147	300
Natural gas (mcf/d)	**17,864**	11,093	61
Total (boe/d)	**8,092**	**4,182**	94
Percentage of oil and natural gas liquids	**63%**	**56%**	

Average production for the first quarter of 2015 increased by 5% to 8,092 boe/d from 7,681 boe/d in the fourth quarter of 2014, and increased by 94% from 4,182 boe/d in the first quarter of 2014. The production increase during the first quarter of 2015, compared to the fourth quarter of 2014, was the result of a full quarter of production from the 13 (10.9 net) Cardium oil wells that came on-stream late in the fourth quarter of 2014 in the Wilson Creek area, adding an incremental 1,527 boe/d to the quarter average. These production additions were offset by expected declines from existing production and from TransCanada Pipeline ("TCPL") curtailments and production downtime associated with the Wilson Creek treater fire, which resulted in 280 boe/d of lost production to the quarter average.

Average crude oil and natural gas liquids production in the first quarter of 2015 was up 7% to 5,115 bbls/d compared to 4,761 bbls/d in the fourth quarter of 2014. Crude oil and natural gas liquids production increased by 7% quarter-over-quarter as a result of a full quarter of production from the 13 (10.9 net) Cardium oil wells that came on-stream late in the fourth quarter of 2014 in the Wilson Creek area, adding an incremental 1,166 bbls/d to the quarter average, offset by expected declines from existing production and from TCPL curtailments and production downtime associated with the Wilson Creek treater fire, which resulted in 164 bbls/d of lost production to the quarter average.

The oil and natural gas liquids weighting increased to 63% of total production in the first quarter of 2015 compared to 62% during the fourth quarter of 2014. 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 Alder Flats and Brazeau areas which have a higher natural gas weighting.

Natural gas production averaged 17,864 mcf/d in the first quarter of 2015 compared to 17,518 mcf/d in the fourth quarter of 2014. Production increased quarter-over-quarter as a result of a full quarter of production from the 13 (10.9 net) Cardium oil wells that came on-stream late in the fourth quarter of 2014 in the Wilson Creek area, adding an incremental 2,168 mcf/d to the quarter average, offset by expected declines from existing production and from TCPL curtailments and production downtime associated with the Wilson Creek treater fire, which resulted in 698 mcf/d of lost production to the quarter average.

Increases in production for the three months ended March 31, 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, and the successful 2014 drilling programs, offset by expected declines from existing production.

The Company drilled two net Cardium horizontal oil wells in Wilson Creek in early January 2015, bringing the total to three net Cardium horizontal oil wells that have been drilled but were not fracture stimulated or placed on production. During the first quarter of 2015, Tamarack elected to exercise fiscal prudence with the current commodity price environment in order to preserve the Company's target return on capital. As a result, these three wells were not fracture stimulated. Deferring these wells, combined with the Alder Flats well that has been shut-in since the third quarter of 2014 due to third party facility constraints, will allow Tamarack to ramp up production when economic conditions improve. The Company estimates it has 1,205 boe/d behind pipe in the Wilson Creek / Alder Flats area that has been shut in to preserve economics. The Company may elect to fracture stimulate the three newly drilled Cardium wells when a combination of an increase in commodity prices and appropriate service cost reductions enable these wells to achieve a one-year payout or better.

Petroleum, Natural Gas Sales and Royalties

	Three months ended March 31,		
	2015	2014	% change
Revenue			
Oil and NGLs	**$20,628,395**	$19,575,471	5
Natural gas	**4,682,238**	4,922,784	(5)
Total	**$25,310,633**	$24,498,255	3
Average realized price			
Light oil ($/bbl)	**48.33**	94.82	(49)
Heavy oil ($/bbl)	**39.18**	77.30	(49)
Natural gas liquids ($/bbl)	**25.43**	79.84	(68)
Combined average oil and NGLs ($/boe)	**44.81**	93.23	(52)
Natural gas ($/mcf)	**2.91**	4.93	(41)
Revenue $/boe	**34.75**	65.09	(47)
Benchmark pricing:			
Edmonton Par (Cdn$/bbl)	**52.60**	99.56	(47)
Hardisty Heavy (Cdn$/bbl)	**42.64**	83.87	(49)
AECO daily index (Cdn$/mcf)	**2.76**	5.67	(51)
AECO monthly index (Cdn$/mcf)	**2.94**	4.74	(38)

Royalty expenses	**$2,756,164**	$2,959,833	(7)
$/boe	**3.78**	7.86	(52)
percent of sales	**11**	12	(8)

Revenue from crude oil, natural gas and associated natural gas liquids sales decreased by 25% to $25,310,633 in the first quarter of 2015 from $33,838,539 in the fourth quarter of 2014 and increased by 3% as compared to $24,498,255 in the first quarter of 2014. Natural gas prices averaged $2.91/mcf and oil and natural gas liquids prices averaged $44.81/bbl in the first quarter of 2015 as compared to $3.91/mcf and $62.87/bbl in the fourth quarter of 2014 and compared to $4.93/mcf and $93.23/bbl in the first quarter of 2014, respectively.

The 25% decrease in revenue during the first quarter of 2015, when compared to the fourth quarter of 2014, was primarily the result of a 29% decrease in crude oil and natural gas liquids pricing and a 26% decrease in natural gas pricing partially offset by a 7% increase in crude oil and natural gas liquids production and a 2% increase in natural gas production.

The 3% increase to revenue in the first quarter of 2015, compared to the first quarter of 2014, was primarily caused by a 119% increase in crude oil and natural gas liquids production and a 61% increase in natural gas production, partially offset by a 52% decrease in crude oil and natural gas liquids pricing and a 41% decrease in natural gas pricing.

The Company's realized crude oil and natural gas liquids prices for the three months ended March 31, 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 have 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 months ended March 31, 2015 and 2014 generally correlate to the Hardisty Heavy price for the same period.

The Company's realized natural gas prices for the three months ended March 31, 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 March 31, 2015, the Company held derivative commodity contracts aggregated as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $93.25
Crude oil	1,000 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $84.38
Crude oil	1,000 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $82.69
Natural gas	4,000 GJ/day	April 1, 2015 – June 30, 2015	AECO fixed price	Cdn $2.67
Natural gas	4,000 GJ/day	July 1, 2015 – September 30, 2015	AECO fixed price	Cdn $2.69
Natural gas	2,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.05

At March 31, 2015, the commodity contracts were fair valued with an asset of $5,661,629 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized loss of $2,809,281 recorded in earnings.

At March 31, 2015, the Company held no physical commodity contracts.

Since March 31, 2015, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	US $60.12
Crude oil	500 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	US $62.00
Crude oil	500 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.52
Crude oil	200 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $76.00
Crude oil	700 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.86
Crude oil	900 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $75.91
Crude oil	1,100 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $75.43
Crude oil	300 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $75.90

Royalty expenses for the first quarter of 2015 were $3.78/boe or $2,756,164, representing 11% of revenue, compared to a royalty expense for the fourth quarter of 2014 of $6.20/boe or $4,380,201, representing 13% of revenue. The Company expects royalty rates to remain lower in 2015 compared to those realized in 2014 due to lower commodity prices and the number of new wells being drilled on Company owned lands with the initial Crown royalty incentive rate of 5%.

The royalty expenses for the first quarter of 2014 were $7.86/boe or $2,959,833, representing 12% of revenue. The decrease in royalties as a percentage of revenue in the first quarter of 2015, as compared to the first 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 area of Alberta (the “Wilson Creek Acquisition”).

Production Expenses

	Three months ended March 31,		
	2015	2014	% change
Total production expenses	**$9,139,317**	$4,986,256	83
Total ($/boe)	**$12.55**	$13.25	(5)

Production expenses for the first quarter of 2015 were $12.55/boe compared to $12.59/boe incurred during the fourth quarter of 2014. The production expenses decreased by $1.33/boe in the first quarter of 2015, offset by an increase to the rental fee increase of $1.28/boe, as a result of the facility rental arrangement effective January 2015. The Company has been implementing cost cutting measures in the Wilson Creek area since closing the Wilson Creek Acquisition at the end of the third quarter of 2014. Tamarack has successfully reduced Wilson Creek production costs from what the previous operator experienced in 2014 of $17.56/boe to under $8.00/boe in the first quarter of 2015.

On a dollar basis, overall costs increased in the first quarter of 2015 by 3% to $9,139,317 from the $8,895,326 incurred during the fourth quarter of 2014. The increase in total production costs resulted from the 5% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset from lower costs in the Wilson Creek area.

Total production expenses on a boe basis were $12.55/boe in the first quarter of 2015 compared to $13.25/boe during the first quarter of 2014. Production expenses for the three months ended March 31, 2015 increased by 83% to $9,139,317, compared to $4,986,256 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 94% increase in production and as a result of the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

The first quarter 2015 operating costs were $1.90/boe lower than budgeted ($12.55/boe versus $14.45/boe) due to the reduction of operating costs primarily in the Wilson Creek area. Future operating costs on a boe basis will fluctuate as production increases or decreases, as a portion of the operating costs are fixed.

Operating Netback

	Three months ended March 31,		
($/boe)	**2015**	2014	% change
Average realized sales	**34.75**	65.09	(47)
Royalty expenses	**(3.78)**	(7.86)	(52)
Production expenses	**(12.55)**	(13.25)	(5)
Operating field netback	**18.42**	43.98	(58)
Realized commodity hedging gain (loss)	**5.00**	(3.46)	245
Operating netback	**23.42**	40.52	(42)

The operating netback for the first quarter of 2015 decreased by 26% to $23.42/boe compared to $31.74/boe during the fourth quarter of 2014. The decrease was the result of a 29% decrease in oil and natural gas liquids prices ($44.81/bbl versus $62.87/bbl) and a 26% decrease in natural gas prices ($2.91/mcf versus $3.91/mcf), partially offset by a 39% decrease in royalty expense per boe ($3.78/boe versus $6.20/boe) and a realized hedging gain of $5.00/boe during the first quarter of 2015, compared to a realized hedging gain of $2.64/boe during the fourth quarter 2014.

The operating netback for the first quarter of 2015 decreased by 42% to $23.42/boe compared to $40.52/boe during the first quarter of 2014. The decrease was the result of a 52% decrease in oil and natural gas liquids prices ($44.81/bbl versus $93.23/bbl) and a 41% decrease in natural gas prices ($2.91/mcf versus $4.93/mcf), partially offset by a decrease of 52% in royalty expense per boe ($3.78/boe versus $7.86/boe), a realized hedging gain of $5.00/boe during the first quarter 2015 compared to a $3.46/boe realized hedging loss during the first quarter of 2014 and a 5% decrease in operating expense per boe ($12.55/boe versus $13.25/boe).

General and Administrative Expenses

	Three months ended March 31,		
	2015	2014	% change
Gross costs	**$2,470,521**	$1,707,943	69
Capitalized costs and recoveries	**(397,830)**	(385,159)	111
General and administrative costs	**$2,072,691**	$1,322,784	57
Total ($/boe)	**$2.85**	$3.51	(19)

General and administrative expenses for the first quarter of 2015 were $2.85/boe on costs of $2,072,691 compared to $2.69/boe on costs of $1,897,641 in the fourth quarter of 2014. The higher costs in the first quarter of 2015 were related to the full quarter effect of the increased general and administrative costs associated with the Wilson Creek Acquisition. The increase in the cost per boe in the first quarter of 2015 from the fourth quarter of 2014 was the result of increased general and administrative costs associated with the Wilson Creek Acquisition, partially offset by a 5% increase in production. The Company originally budgeted general and administrative costs to be between $3.50/boe and $3.75/boe for 2015, however the Company was successful in reducing general and administrative costs through cost cutting measures other than by reducing staff.

General and administrative expenses for the first quarter of 2014 were $3.51/boe on costs of $1,322,784. The increase in costs to $2,072,691 in the first quarter of 2015 was related to increases in the employee count and to office rent. The decrease in the costs per unit in the first quarter of 2015 was related to a 94% increase in production, partially offset by increased staffing costs.

Stock-based Compensation Expenses

Stock-based compensation expenses of $739,513, relating to the preferred shares, stock options and restricted share awards for the three months ended March 31, 2015, were higher compared to $537,802 for the same period 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 $413,392 of stock-based compensation expenses relating to exploration and development activities for the three months ended March 31, 2015, compared to capitalizing $229,610 for the same period in 2014.

Interest

Interest expense was $1,241,534 for the three months ended March 31, 2015, compared to $482,689 for the same period in 2014. The Company has drawn $112,951,205 on its revolving credit facility at March 31, 2015, compared to $17,493,528 drawn on its line at March 31, 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 March 31,		
	2015	2014	% change
Depletion and depreciation	**$15,927,212**	$7,302,574	118
Amortization of undeveloped leases	**204,927**	732,533	(72)
Accretion	**257,100**	145,073	77
Total	**$16,389,239**	$8,180,180	100
Depletion and depreciation ($/boe)	**$21.87**	$19.40	13
Amortization ($/boe)	**0.28**	1.95	(86)
Accretion ($/boe)	**0.35**	0.39	(10)
Total ($/boe)	**$22.50**	$21.74	3

Depletion, depreciation, amortization and accretion expense on a boe basis for the first quarter of 2015 was 9% lower at $22.50/boe, compared to $24.77/boe during the fourth quarter of 2014. The first quarter decrease in depletion, depreciation, amortization, and accretion expense rate was a result of the $56,290,000 impairment taken at the end of the fourth quarter 2014 on certain natural gas, heavy oil and Viking cash generating units (“CGUs”). Depletion, depreciation, amortization and accretion expense for the first quarter of 2015 was $16,389,239, compared to $17,502,212 during the fourth quarter of 2014. The 6% decrease in total depletion, depreciation, amortization, and accretion expense was the result of the 5% increase in production, partially offset by the lower per unit expense on a boe basis.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the first quarter of 2015 was $22.50/boe, compared to $21.74/boe during the first quarter of 2014. Depletion, depreciation, amortization, and accretion expense for the first quarter of 2015 was $16,389,239, compared to $8,180,180 during the first quarter of 2014. The first quarter 2015 increase in depletion, depreciation, amortization, and accretion expense rate as compared to the first quarter of 2014 was a result of the increased percentage of overall production related to the higher cost Cardium, Viking and heavy oil properties. The 100% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 94% increase in production and the higher per unit depletion, depreciation and accretion expense on a boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three months ended March 31, 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 months ended March 31, 2015, a deferred income tax recovery of $1,500,705 was recognized, compared to a deferred income tax expense of $776,161 for the same period in 2014. There was a deferred tax recovery during the first quarter of 2015 due to a loss before taxes, while in the first quarter of 2014 a deferred tax expense was recorded due to income before taxes being recognized.

Funds from Operations and Net Income

Funds from operations during the first quarter of 2015 were $13,742,786 ($0.18 per share basic and diluted) compared to funds from operations of $19,127,813 ($0.25 per share basic and diluted) for the fourth quarter of 2014. The decrease in funds from operations is primarily the result of the 29% decrease in crude oil and natural gas liquids pricing and a 26% decrease in natural gas pricing, partially offset by a higher realized hedging gain, lower royalty expense and a 5% increase in production.

Funds from operations during the three months ended March 31, 2015 were $13,742,786 ($0.18 per share basic and diluted), compared to funds from operations of $13,445,163 ($0.26 per share basic and $0.25 per share diluted) for the same period in 2014. The increase in funds from operations was primarily the result of a realized hedging gain in the first quarter of 2015 compared to a realized hedging loss in the first quarter of 2014 and a 94% increase in production. This was partially offset by the 52% decrease in crude oil and natural gas liquids pricing, a 41% decrease in natural gas pricing and higher production expenses related to the increased production.

The Company had a net loss of $5,241,630 ($0.07 per share basic and diluted) during the three months ended March 31, 2015, compared to a net loss of $38,991,202 ($0.50 per share basic and diluted) for the fourth quarter of 2014. The Company recorded a lower net loss for the three months ended March 31, 2015 as compared to the fourth quarter of 2014 as a result of both an impairment to property, plant and equipment and an impairment of exploration and evaluation assets due to the decrease in oil and natural gas liquids pricing taken at the end of 2014. This was partially offset an unrealized loss on financial instruments taken in the first quarter of 2015 as compared to an unrealized gain in the fourth quarter of 2014, lower deferred income tax recovery in the first quarter of 2015, a 29% decrease in crude oil and natural gas liquids pricing and a 26% decrease in natural gas pricing.

The Company had net loss of $5,241,630 ($0.07 per share basic and diluted) during the three months ended March 31, 2015, compared to net income of $1,790,681 ($0.03 per share basic and diluted) for the same period in 2014. The Company recorded a net loss for the three months ended March 31, 2015 as compared to the same period in 2014 as a result of 52% decrease in crude oil and natural gas liquids pricing, a 41% decrease in natural gas pricing, higher depletion, depreciation, amortization and accretion expense and higher production expenses related to the increased production, partially offset by a realized hedging gain in the first quarter of 2015 compared to a realized hedging loss in the first quarter of 2014 and a 94% 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 March 31,		
	2015	2014	% change
Land	**$75,622**	$2,263,921	(97)
Geological and geophysical	**30,506**	99,225	(69)
Drilling and completion	**4,608,729**	20,887,349	(78)
Equipment and facilities	**1,966,669**	2,029,139	(3)
Capitalized G&A	**167,231**	111,241	50
Office equipment	**–**	5,024	(100)
Total capital expenditures	**$6,848,757**	$25,395,899	(73)
Proceeds from disposal of property, plant and equipment	**(1,820,583)**	(383,853)	374
Total net capital expenditures	**$5,028,174**	$25,012,046	(80)

During the first quarter of 2015, the Company drilled 2 (2.0 net) horizontal Cardium wells in the Wilson Creek area. The Company also completed construction on the Hatton heavy oil battery and continued the building of a compressor station in Alder Flats. The Company has budgeted to spend $47 million in 2015, $10.5 million in the first half and $36.5 million in the second half. With a back-end weighted capital expenditure program, the Company is anticipating a reduction in service costs during the second half of 2015 resulting improving capital efficiencies.

2015 Drilling Summary (including wells spudded by March 31, 2015)		
	Gross	Net
Cardium	2.0	2.0
	2.0	2.0

For the three months ended March 31, 2015, the Company disposed of its interest in certain oil and gas properties for $1,820,583. Production associated with this property was 49 boe/d at the time of the dispositions. The Company will continue to dispose of non-core assets.

The Company’s net undeveloped acreage was 177,228 acres at the end of the first quarter of 2015.

Liquidity and Capital Resources

Tamarack’s net debt, including working capital deficiency excluding the fair value of financial instruments, was $121,159,015 at March 31, 2015. Tamarack’s net debt at March 31, 2014 was $37,130,296 and at December 31, 2014 was $129,798,673. The Company was successful in reducing net debt by $8,639,658 during the first quarter of 2015 by realizing higher funds from operations than capital expenditures. Tamarack’s net debt at March 31, 2015 to annualized funds from operations in the first quarter of 2015 was 2.2 times, compared to 0.7 times at March 31, 2014 and 1.7 times at December 31, 2014. The Company is currently on target to achieve its goal of reducing its net debt to between $116 and $118 million by the end of the second quarter of 2015.

At March 31, 2015, there were 77,928,466 common shares, 1,176,000 preferred shares, 4,012,718 options and 406,500 restricted share awards outstanding. At May 12, 2015 there were 77,928,466 common shares, 1,176,000 preferred shares, 4,069,718 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's weighted average basic common shares outstanding during the three months ended March 31, 2015 was 77,928,466.

At March 31, 2015, the Company had a revolving credit facility in the amount of $140 million and a $10 million operating facility (collectively the "Facility"). The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 30, 2015. If not extended, the facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date. 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 credit 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 credit 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 in May 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.

With the recent decrease in commodity prices and increased volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by limiting capital spending to projected cash flow from operations based on conservative price estimates. Tamarack has always been a rate of return driven company focused on drilling wells that target a return on capital cost payout of 1.5 years or less. With the lower commodity price environment and cost of services experienced in the first quarter of 2015, the number of investment opportunities able to deliver these types of economic returns has been drastically reduced. Although Tamarack believes it has some of the most economic drilling prospects in the basin, management has prudently elected to significantly reduce its drilling program compared to 2014 in order to preserve capital, prospect the highest returns and ensure an expedited return on future capital deployed. The decision to begin allocating capital in 2015 toward drilling activities will be based on the Company's ability to reduce costs from 2014 levels and realize commodity price improvements to allow the projects to be able to payout in 1.5 years or less.

The Company plans to limit its 2015 capital expenditure program to spending within cash flow and will back-end weight the capital program to pay down debt during the first half of 2015 and maintain financial flexibility. Tamarack is prepared to adjust its capital budget accordingly to account for changes in commodity prices as the year progresses. The Company wants to maintain as much 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.

2015 Guidance

On January 28, 2015 the Company announced its Board of Directors approved the 2015 capital budget and 2015 guidance based on a WTI price of $50/bbl ($46/bbl Q1/15, $54/bbl Q4/15), an Edmonton Par price average of $51.60/bbl, an AECO price average of $2.65/GJ and a $0.85 Canadian dollar.

The 2015 capital budget and current guidance are as follows:

- $47 million capital program with only $10.5 million being spent in the first half of 2015.
- Production was estimated to average 8,000 boe/d in the first quarter of 2015 with a 60% weighting to oil and natural gas liquids. This forecast excludes behind pipe volumes of approximately 1,205 boe/d and 435 boe/d shut-in to preserve economics.
- Based on strip pricing in mid-January 2015, the Company expects to reduce net debt to approximately $116 to $118 million by the end of the second quarter of 2015.

The Company exceeded first quarter 2015 production guidance of 8,000 boe/d by realizing an average rate of 8,092 boe/d and 63% oil and natural gas liquids weighting.

Commitments

In the normal course of business, the Company has obligations representing contracts and other commitments with an estimated payment of $538,424 for 2015, $418,178 for 2016 and $99,594 for 2017. These obligations are related to office lease commitments.

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 March 31, 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 sales pipeline built by a mid-stream company, Tamarack has a take or pay obligation of $1.43/bbl on a minimum of 1,887 bbls/d of crude oil or condensate. The remaining term is 43 months. During the first quarter of 2015, the Company delivered an average of 1,958 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 to access four facilities.

The following table summarizes the Company's commitments at March 31, 2015:

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease	538,424	418,178	99,594	–	–	–	–	–
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	16,105,018	13,400,303	12,841,719	3,742,125	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 March 31,	
	2015	2014
Cash provided by operating activities	**$16,871,206**	$15,894,869
Abandonment expenditures	**66,554**	39,177
Changes in non-cash working capital	**(3,194,974)**	(2,488,883)
Funds from operations	**$13,742,786**	$13,445,163
Funds from operation per share -basic	**$ 0.18**	$ 0.26
Funds from operation per share -diluted	**$ 0.18**	$ 0.25

(b) **Operating Netback** - Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and operating costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates its field level profitability relative to current commodity prices. The calculation of the Company's netbacks can be seen on page 6 in the section titled "Operating Netback."

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

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

	March 31, 2015	December 31, 2014
Cash and cash equivalents	$ –	$830,104
Accounts receivables	14,769,708	20,370,676
Prepaid expenses	641,187	810,983
Accounts payable and accrued liabilities	(23,618,705)	(51,610,436)
Bank debt	(112,951,205)	(100,200,000)
Net debt	$(121,159,015)	$(129,798,673)

Selected Quarterly Information

Three months ended	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013
Sales volumes								
Natural gas *(mcf/d)*	**17,864**	17,518	12,462	12,033	11,093	10,349	7,767	7,125
Oil and NGLs *(bbls/d)*	**5,115**	4,761	3,688	3,197	2,333	2,611	1,867	1,702
Average boe/d *(6:1)*	**8,092**	7,681	5,765	5,203	4,182	4,336	3,162	2,890
Product prices								
Natural gas *($/mcf)*	**2.91**	3.91	4.13	4.37	4.93	3.72	2.99	3.61
Oil and NGLs *($/bbl)*	**48.33**	62.87	90.19	94.65	93.23	77.78	98.65	87.09
Oil equivalent *($/boe)*	**34.75**	47.89	66.62	68.27	65.09	55.72	65.60	60.21
(000s, except per share amounts)								
Financial results								
Gross revenues	**25,311**	33,839	35,333	32,322	24,498	22,224	19,082	15,830
Funds from operations	**13,743**	19,128	15,809	17,790	13,445	10,505	10,260	8,823
Per share – basic	**0.18**	0.25	0.26	0.29	0.26	0.24	0.35	0.30
Per share – diluted	**0.18**	0.25	0.26	0.29	0.25	0.23	0.34	0.30
Net income (loss)	**(5,242)**	(38,991)	6,791	5,243	1,791	10,855	3,721	(60)
Per share – basic	**(0.07)**	(0.50)	0.11	0.09	0.03	0.37	0.13	0.00
Per share – diluted	**(0.07)**	(0.50)	0.11	0.08	0.03	0.37	0.12	0.00
Additions to property and equipment, net of proceeds	**5,028**	26,774	196,375	40,742	25,012	22,010	10,691	13,057
Net property acquisitions	**–**	–	166,057	–	–	–	–	–
Corporate acquisitions	–	–	–	–	–	57,135	–	–
Total assets	**482,227**	497,578	525,003	319,065	288,608	269,707	170,610	168,090
Working capital (deficiency)(1)	**(121,159)**	(129,799)	(121,684)	(59,490)	(37,130)	(81,764)	(57,088)	(56,649)
Bank debt(2)	**112,951**	100,200	100,275	43,735	17,494	71,796	50,876	45,780
Decommissioning obligations	**45,340**	41,357	36,732	20,956	20,484	19,802	12,795	12,576
Deferred income tax (asset)	**(28,802)**	(27,299)	(16,870)	(17,743)	(19,681)	(19,467)	(8,717)	(10,029)

(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"). As a result, oil and natural gas liquids weighting has increased from 59% of total production in the second quarter of 2013 to 63% in the first quarter of 2015.
- On August 19, 2013, the Company entered into a farm-in agreement with an industry major to earn 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 $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition and recorded $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.

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 "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "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.
- Anticipated reductions in net debt in 2015.
- Future operating costs on a boe basis.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.

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

With respect to the forward-looking statements contained in this MD&A, we have 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)

	March 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ –	$830,104
Accounts receivable	14,769,708	20,370,676
Prepaid expenses and deposits	641,187	810,983
Fair value of financial instruments (note 3)	5,661,629	8,470,910
	21,072,524	30,482,673
Property, plant and equipment (note 4)	428,518,821	435,328,116
Exploration and evaluation assets (note 5)	3,833,722	4,468,823
Deferred tax asset	28,801,630	27,298,825
	$482,226,697	$497,578,437
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$23,618,705	$51,610,436
Bank debt (note 10)	112,951,205	100,200,000
Decommissioning obligations (note 6)	45,340,343	41,356,532
Shareholders' equity:		
Share capital (note 8)	336,080,362	336,086,662
Contributed surplus	14,084,263	12,931,358
Deficit	(49,848,181)	(44,606,551)
	300,316,444	304,411,469
Commitments and contingencies (note 12)		
	$482,226,697	$497,578,437

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (loss) and Comprehensive Income (loss)
For the three months ended March 31, 2015 and 2014
(unaudited)

	2015	2014
Revenue:		
Oil and natural gas	$25,310,633	$24,498,255
Royalties	(2,756,164)	(2,959,833)
Realized gain (loss) on financial instruments (note 3)	3,641,859	(1,301,530)
Unrealized loss on financial instruments (note 3)	(2,809,281)	(1,058,455)
	23,387,047	19,178,437
Expenses:		
Production	9,139,317	4,986,256
General and administration	2,072,691	1,322,784
Stock-based compensation (note 11)	739,513	537,802
Finance expense	1,498,634	627,762
Depletion, depreciation and amortization	16,132,139	8,035,107
Loss on disposition of property, plant and equipment (note 4)	547,088	1,101,884
	30,129,382	16,611,595
Income (loss) before taxes	(6,742,335)	2,566,842
Deferred income tax recovery (expense)	1,500,705	(776,161)
Net income (loss) and comprehensive income (loss)	$(5,241,630)	$1,790,681
Net income (loss) per share (note 9):		
Basic	$(0.07)	$ 0.03
Diluted	$(0.07)	$ 0.03

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 warrants	–	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
Share issue costs, net of tax of $2,100	–	(6,300)	–	–	(6,300)
Stock-based compensation	–	–	1,152,905	–	1,152,905
Net loss	–	–	–	(5,241,630)	(5,241,630)
Balance at March 31, 2015	77,928,466	$336,080,362	$14,084,263	$(49,848,181)	$300,316,444

	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	14,000,000	60,200,000	–	–	60,200,000
Share issue costs, net of tax of $990,020	–	(2,970,061)	–	–	(2,970,061)
Stock-based compensation	–	–	767,412	–	767,412
Net income	–	–	–	1,790,681	1,790,681
Balance at March 31, 2014	60,168,718	$215,204,664	$10,255,008	$(17,648,509)	$207,811,163

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three months ended March 31, 2015 and 2014
(unaudited)

	2015	2014
Cash provided by (used in):		
Operating:		
Net income (loss)	$(5,241,630)	$1,790,681
Items not involving cash:		
Depletion, depreciation and amortization	16,132,139	8,035,107
Stock-based compensation	739,513	537,802
Loss on disposition of property, plant and equipment	547,088	1,101,884
Accretion expense on decommissioning obligations	257,100	145,073
Unrealized loss on financial instruments	2,809,281	1,058,455
Deferred income tax expense (recovery)	(1,500,705)	776,161
Funds from operations	13,742,786	13,445,163
Abandonment expenditures (note 6)	(66,554)	(39,177)
Changes in non-cash working capital (note 7)	3,194,974	2,488,883
Cash provided by operating activities	16,871,206	15,894,869
Financing:		
Change in bank debt	12,751,205	(54,302,417)
Proceeds from issuance of common shares	–	60,200,000
Share issue costs	(8,400)	(3,960,081)
Cash provided by financing activities	12,742,805	1,937,502
Investing:		
Property, plant and equipment additions	(6,477,690)	(19,990,082)
Exploration and evaluation additions	(371,067)	(5,405,817)
Proceeds from disposal of property, plant and equipment	1,820,583	383,853
Changes in non-cash working capital (note 7)	(25,415,941)	7,179,675
Cash used in investing activities	(30,444,115)	(17,832,371)
Change in cash and cash equivalents	(830,104)	–
Cash and cash equivalents, beginning of period	830,104	–
Cash and cash equivalents, end of period	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" 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 May 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 March 31, 2015, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value
Crude oil	100 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $104.80	$380,075
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $102.25	$713,825
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $100.50	$682,033
Crude oil	300 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $100.00	$1,009,425
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $61.10	($33,731)
Crude oil	300 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $102.70	$978,530
Crude oil	200 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $100.25	$607,464
Crude oil	200 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $70.00	$53,226
Crude oil	300 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $65.05	($56,203)
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $101.50	$868,631
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $76.00	$169,598
Crude oil	200 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $75.00	$94,790
Crude oil	200 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $72.20	$43,619
Natural gas	2,000 GJ/day	April 1, 2015 – June 30, 2015	AECO fixed price	Cdn $2.66	$25,012
Natural gas	2,000 GJ/day	April 1, 2015 – June 30, 2015	AECO fixed price	Cdn $2.68	$30,656
Natural gas	2,000 GJ/day	July 1, 2015 – September 30, 2015	AECO fixed price	Cdn $2.67	$21,416
Natural gas	2,000 GJ/day	July 1, 2015 – September 30, 2015	AECO fixed price	Cdn $2.70	$27,003
Natural gas	2,000 GJ/day	October 1, 2015 – December 31, 2015	AECO fixed price	Cdn $3.05	$46,260
					$5,661,629

3. Commodity contracts (continued):

At March 31, 2015, the commodity contracts were fair valued with an asset of $5,661,629 (December 31, 2014 - $8,470,910) recorded on the balance sheet and an unrealized loss of $2,809,281 recorded in earnings.

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement the realized benefit or loss is recognized in oil and natural gas revenue. At March 31, 2015, the Company held no physical commodity contracts.

Since March 31, 2015, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	300 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	US $60.00
Crude oil	200 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	US $60.30
Crude oil	200 bbls/day	September 1, 2015 – September 30, 2015	WTI fixed price	US $62.00
Crude oil	200 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $61.30
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	US $60.00
Crude oil	200 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn$76.00
Crude oil	300 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $60.00
Crude oil	400 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $61.50
Crude oil	300 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $74.75
Crude oil	200 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.10
Crude oil	200 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.35
Crude oil	300 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $77.00
Crude oil	300 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $75.25
Crude oil	600 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $75.00
Crude oil	200 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $77.00
Crude oil	300 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $75.90

4. 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
Cash additions	6,477,690		6,477,690
Decommissioning costs	3,856,401	–	3,856,401
Stock-based compensation	413,392	–	413,392
Transfer from exploration and evaluation assets	801,241	–	801,241
Disposals	(2,562,187)	–	(2,562,187)
Balance at March 31, 2015	$594,480,384	$332,484	$594,812,868
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	15,915,522	11,690	15,927,212
Disposals	(131,380)	–	(131,380)
Balance at March 31, 2015	$166,104,781	$189,266	$166,294,047

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2014	$435,173,208	$154,908	$435,328,116
At March 31, 2015	$428,375,603	$143,218	$428,518,821

For the three months ended March 31, 2015 the Company disposed of its interest in certain oil and gas properties for $1,820,583.

The calculation of depletion at March 31, 2015 includes estimated future development costs of $374,258,000 (December 31, 2014 – $374,258,000) associated with the development of the

4. Property, plant and equipment (continued):

Company's proved plus probable reserves and excludes salvage value of $23,309,000 (December 31, 2014 – $23,400,000).

5. 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	371,067
Transfer to property, plant and equipment	(801,241)
Balance at March 31, 2015	$23,200,875
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	204,927
Balance at March 31, 2015	$ 19,367,153

	Total
Carrying amounts:	
At December 31, 2014	$4,468,823
At March 31, 2015	$3,833,722

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.

6. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately $43.1 million at March 31, 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 March 31, 2015 as presented in the table below:

	2015	2014
Balance, beginning of the period	**$41,356,532**	$19,801,991
Liabilities incurred	**164,945**	3,504,114
Liabilities acquired	**–**	7,550,058
Change in estimates	**3,691,456**	3,224,957
Change in discount rate on acquisition	**–**	7,770,729
Expenditures	**(66,554)**	(678,886)
Liabilities disposed	**(63,136)**	(540,597)
Accretion	**257,100**	724,166
Balance, end of the period	**$45,340,343**	$41,356,532

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.

7. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	2015	2014
Source/(use of cash):		
Accounts receivable	**$5,600,968**	$(2,042,915)
Prepaid expenses and deposits	**$169,796**	37,222
Accounts payable and accrued liabilities	**(27,991,731)**	11,674,251
	$(22,220,967)	$9,668,558
Related to operating activities	**$3,194,974**	$2,488,883
Related to investing activities	**$(25,415,941)**	$7,179,675

8. Share capital:

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

9. 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:

	2015	2014
Net income (loss) for the period	**$(5,241,630)**	$1,790,681
Weighted average shares - basic	**77,928,466**	52,546,496
Weighted average shares - diluted	**77,928,466**	53,646,513
Net income (loss) per share-basic	**$(0.07)**	$ 0.03
Net income (loss) per share-diluted	**$(0.07)**	$ 0.03

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three months ended March 31, 2015, 5,595,218 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 months ended March 31, 2014, 460,804 stock options and preferred shares were excluded from the diluted earnings per share as they were anti-dilutive.

10. Bank debt:

At March 31, 2015, the Company has a revolving credit facility in the amount of $140,000,000 and a $10,000,000 operating facility (collectively the “Facility”). The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 30, 2015. 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 30, 2016. 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 credit 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 credit facility has been secured by a $300,000,000 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 in May 2015.

Pursuant to the terms of the credit 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 March 31, 2015, the Company had utilized the Facility in the amount of $112,951,205 and the Company was compliant with its working capital ratio at 2.2 to 1.0.

10. Bank debt (continued):

As at March 31, 2015, the Company had letter of guarantees outstanding in the amount of $43,980 against the credit facility.

11. Share-based payments:

(a) Preferred share plan:

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

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 7,792,847 options or restricted share units to its employees, directors and consultants of which 5,011,948 options, preferred shares and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were no options granted during the period.

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
Forfeited	**(134,668)**	**3.25**
Outstanding, March 31, 2015	**4,012,718**	**$ 3.73**

The following table summarizes information about stock options outstanding and exercisable at March 31, 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	2.5	675,369	$2.12
$ 3.01 – 5.00	2,463,667	$3.85	3.4	984,998	$3.93
$ 5.01 – 6.82	466,000	$6.82	4.4	–	–
$ 1.86 – 6.82	**4,012,718**	**$3.73**	**3.3**	**1,660,367**	**$3.20**

11. Share-based payments (continued):

(c) Restricted stock unit plan

The Company has a restricted stock unit plan that allows the board of directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted stock unit plan, each restrictive share award entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant.

The following table summarizes information about the restricted share awards at March 31, 2015:

	Number of awards
Outstanding, December 31, 2014 and March 31, 2015	**406,500**

12. 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 $538,424 for 2015, $418,178 for 2016 and $99,594 for 2017. These obligations are related to office lease commitments.

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 March 31, 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 43 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 to access four facilities.

The following table summarizes the Company's commitments at March 31, 2015:

	2015	2016	2017	2018	2019	2020	2021	2022
Office lease	538,424	418,178	99,594	–	–	–	–	–
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	16,105,018	13,400,303	12,841,719	3,742,125	3,742,125	3,742,125	3,742,125	1,871,063

12. Commitments and contingencies (continued):

(b) Contingencies

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

CORPORATE INFORMATION

Directors

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

Dean Setoguchi(1)(3)

David Mackenzie(1)(2)

Jeff Boyce(2)(3)

Brian Schmidt

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

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Noralee Bradley
Corporate Secretary

Banker

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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