MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis as provided by the management of Raging River Exploration Inc. ("Raging River" or the "Company") is dated May 14, 2018 and should be read in conjunction with the unaudited financial statements for the three months ended March 31, 2018 and the audited financial statements for the year ended December 31, 2017 and the notes thereto. The interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 – "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars, except when noted otherwise.

Description of the Company

Raging River was incorporated as 1646988 Alberta Ltd. pursuant to the *Business Corporations Act* (Alberta) on December 15, 2011 and subsequently changed its name to Raging River Exploration Inc. Raging River is a crude oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are in the Viking light oil resource play in western Canada in addition to the recently added Duvernay light oil resource play.

Unless otherwise indicated herein, all production information presented herein has been presented on a gross basis, which is the Company's working interest prior to deduction of royalties and without including any royalty interests.

FIRST QUARTER 2018 HIGHLIGHTS

- Achieved a quarterly production record with average production of 24,118 boe/d (93% oil) representing an increase of 6% over the comparable period in 2017. This represents a 6% production per share increase from the first quarter of 2017.
- Achieved funds flow from operations of $89 million ($0.38/share basic) relative to $83.9 million ($0.36/share basic) in the fourth quarter of 2017 and $72.8 million ($0.31/share basic) in the first quarter of 2017.
- The Company generated operating netbacks of $44.78/boe on an unhedged basis and funds flow netbacks of $40.99/boe.
- Generated first quarter net earnings of $21.7 million or $10.03/boe.
- Corporate royalties continued to be stable at 9.0% during the quarter.
- Continued diligent cost control with top decile general and administrative costs of $1.05/boe.
- The Company's capital expenditures were $118.4 million inclusive of $5.6 million on land and $112.8 million of exploration and development expenditures resulting in the drilling of 109.7 net Viking crude oil wells and 3.0 net Duvernay crude oils wells at a 100% success rate.
- Maintained balance sheet strength with first quarter net debt of $329 million representing 0.9 times net debt to first quarter annualized funds flow from operations.

REAFFIRMS CREDIT FACILITIES

Raging River's borrowing base was reviewed and we are pleased to announce that the syndicate of lenders underwriting the Company's credit facilities have unanimously reaffirmed the borrowing base at $500 million, on similar terms. The next borrowing base redetermination is scheduled for October 2018.

Petroleum and Natural Gas Operations

Production and Pricing

	Three months ended March 31, 2018	2017	Percent Change
Average daily production			
Light oil and liquids (bbls/d)	21,351	19,476	10
Heavy oil (bbls/d)	1,146	1,419	(19)
Natural gas (mcf/d)	9,722	11,161	(13)
Barrels of oil equivalent (boe/d)	24,118	22,755	6
Raging River average sales price			
Light oil and liquids ($/bbl)	67.68	59.16	14
Heavy oil ($/bbl)	43.75	44.35	(1)
Natural gas ($/mcf)	1.99	2.64	(25)
Barrel of oil equivalent ($/boe)	62.80	54.70	15
Average Benchmark Prices			
Crude oil - WTI (US$/bbl)	62.87	51.90	21
Crude oil – MSW (Cdn$/bbl)	72.17	63.87	13
Crude oil – WCS (Cdn$/bbl)	48.74	49.40	(1)
Natural gas – AECO (Cdn$/mcf)	2.06	2.69	(23)
Exchange rate (US$/Cdn$)	0.79	0.76	4

Revenues

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
Light oil and liquids	129,668	103,623	25
Heavy oil	4,513	5,662	(20)
Natural gas	1,742	2,651	(34)
Royalty	389	81	380
	136,312	112,017	22

The Company takes almost all of its working interest production "in kind" and it is marketed and sold through various credit-worthy commodity purchasers. Raging River's crude oil is marketed under a short-term (30 day) contract with a crude oil marketer and through major North American crude oil purchasers. All of the Company's natural gas is currently sold as spot gas through significant North American natural gas marketers. Commodity prices are affected by both domestic and international factors that are beyond the control of the Company. Prices received for light crude oil are determined by the quality of the crude compared to the benchmark price for Mixed Sweet Blend ("MSW") and Western Canadian Select ("WCS") for heavy crude oil.

In the three months ended March, 2018, the West Texas Intermediate ("WTI") price increased 21% compared to the corresponding period of 2017, resulting in an increase in the Company's realized crude oil price. The Company's light crude oil price averaged $67.68/bbl for the first quarter of 2018, an increase of 14% from $59.16/bbl in the first quarter of 2017. Raging River's average quality adjustment to MSW pricing of $4.49/bbl in the first quarter of 2018 was consistent with the first quarter of 2017. Raging River's realized light oil is priced at Light Smiley in Kerrobert ("KSW") and discounted to MSW due to quality adjustments, net of fees including pipeline tariffs and location differentials.

Although the WTI price strengthened in 2018, the WCS price remained flat in the first quarter of 2018 compared to 2017. The WCS differential to WTI widened in the first quarter of 2018 due to a build up of inventories from transportation bottlenecks that occurred late in 2017. The Company's heavy crude oil price averaged $43.75/bbl for the first quarter of 2018, a slight decrease from $44.35/bbl in the first quarter of 2017. Raging River's average quality adjustment to WCS pricing remained consistent in the three months ended March 31, 2018 at $4.99/bbl from $5.05/bbl in the comparable period of 2017.

Despite a cold winter in 2018, natural gas pricing declined significantly in the first quarter of 2018 from the comparable period in 2017. The growth in natural gas production combined with transportation constraints in western Canada resulted in downward pressure in the AECO natural gas pricing and a decrease in the natural gas price realized by the Company. Raging River's realized natural gas price for the first quarter of 2018 was $1.99 per mcf compared to $2.64 per mcf in the corresponding period.

Drilling and Production

During the first quarter of 2018, the Company drilled a total of 128 (114.7 net) wells resulting in 126 (112.7 net) crude oil wells and 2 (2.0 net) injection wells, for a success rate of 100%.

Production	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16
Light oil and liquids (bbls/d)	21,351	20,891	20,271	18,795	19,476	17,058	15,643	14,603	15,034
Heavy oil (bbls/d)	1,146	1,115	1,135	1,189	1,419	1,780	1,738	171	154
Natural gas (mcf/d)	9,722	10,020	9,629	12,185	11,161	9,652	7,385	7,368	7,900
Total (boe/d)	24,118	23,676	23,011	22,015	22,755	20,447	18,612	16,002	16,505
% increase (decrease) over prior quarter	2%	3%	5%	(3%)	11%	10%	16%	(3%)	12%
Production per 1 million shares	104.3	102.4	99.5	95.2	98.5	88.5	80.8	70.7	76.2
Per share % increase (decrease) over prior quarter	2%	3%	5%	(3%)	11%	10%	14%	(7%)	5%

The Company's production for the first quarter of 2018 increased 6% to 24,118 boe/d from 22,755 boe/d in the first quarter of 2017. The year over year increase was attributable to a successful drilling program in 2018 and 2017. Quarter over quarter, production in the first quarter of 2018, increased 2% to 24,118 boe/d from 23,676 boe/d in the fourth quarter of 2017.

Petroleum and natural gas revenue in the three months period March 31, 2018 was $136.3 million as compared to $112 million in the corresponding period of 2017. This increase was attributable to a 6% increase in production volumes combined with a 15% increase in commodity pricing.

Risk Management Contracts

Raging River periodically enters into risk management contracts to reduce the volatility in cash flows from operations in order to fund the capital expenditure program. The Company is exposed to risks from movements in the crude oil and natural gas price, fluctuations in the US/Cdn dollar exchange rate and interest rates. The Board of Directors has the overall responsibility for the establishment and oversight of the Company's risk management framework. As at March 31, 2018, the Company's risk management contracts include commodity contracts and an interest rate swap.

Commodity contracts

Raging River, as part of our financial management strategy, has adopted a disciplined commodity risk management program. The objective of the risk management program is to reduce volatility in the financial results, protect acquisition economics and stabilize cash flow against the unpredictable commodity price environment. As the Company's production grows, our corporate risk management strategy will be restricted to a maximum hedge of 60% of the trailing month's actual production, allowing the Company to participate in commodity price increases while limiting exposure to declines in commodity prices. The following aggregated contracts were in place as of March 31, 2018:

Contract Type	Type	Term	Volume	Fixed Contract Price	Index
Crude oil	Fixed	Apr 2018 - Dec 2018	2,667 bbl/d	Cdn $68.22	WTI

Interest rate contracts

The Company is exposed to interest rate risk to the extent the bank debt is at a floating or short-term rate of interest. The Company mitigates its exposure to interest rate changes by entering into interest rate swap transactions. At March 31, 2018, Raging River has the following interest rate swap contract outstanding:

Contract Type	Notional Amount	Reference Price	Fixed Contract Price	Maturity date
Interest rate Swap	$100 million	CDOR(1)	2.02%	October 2020

(1) Canadian dollar offered rate

Realized & Unrealized Gain/Loss on Risk Management Contracts

The table summarizes the realized and unrealized gains (losses) by risk management contract:

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
Realized gain (loss) – commodity contracts	(2,991)	273	(1,196)
Realized loss – interest rate swap	(123)	-	(100)
Realized gain (loss) on risk management contracts	(3,114)	273	(1,241)
Unrealized loss – commodity contracts	(3,382)	(1,157)	192
Unrealized gain - interest rate swap	246	-	100
Unrealized loss on risk management contracts	(3,136)	(1,157)	171

The realized gain/loss represents the risk management contracts settled during the three months ended March 31, 2018. Crude oil commodity contracts are referenced to the WTI and settled in Canadian dollars, the realized gains and losses fluctuate based on changes in the WTI price and $US/$Cdn exchange rate. The Company's natural gas commodity contracts are referenced to the AECO index. Interest rate swaps are referenced to the Canadian Dollar Offered Rate ("CDOR") rate.

For the three months ended March, 2018, the Company incurred a realized loss of $3 million compared to a gain of $273 thousand in the corresponding period of 2017 on commodity contracts. The Company had crude oil commodity contracts to fix the WTI at Cdn$68.50/bbl. The WTI settlement price averaged Cdn$79.57/bbl, resulting in a realized loss in the period.

For the three months ended March 31, 2018, a realized loss of $0.1 million was incurred on the Company's interest rate swap as the fixed interest rate of 2.02% exceeded the CDOR rate in the period.

As of March 31, 2018, the fair value of Raging River's outstanding risk management contracts is an unrealized liability of $9.6 million relating to crude oil commodity contracts and an asset of $0.4 million relating to the interest rate swap, as reflected in the interim financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been received as at March 31, 2018, had the contracts been monetized or terminated. Subsequent changes in the fair value of the risk management contracts are recognized in the financial statements and could be materially different than what is recorded at March 31, 2018.

Royalties

	Three months ended March 31,		Percent
	2018	2017	Change
	(thousands of dollars)		
Crown	2,438	2,468	(1)
Saskatchewan resource surcharge	2,040	1,721	19
Freehold and GORR	7,775	6,496	20
	12,253	10,685	15
Percent of total revenue	9.0%	9.5%	(5)
Per boe ($)	5.64	5.22	8

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and the Saskatchewan resource surcharge. Royalties increased to $12.3 million in the three months ended March 31, 2018 from $10.7 million in the comparable period of 2017, primarily as a result of a 6% increase in production volumes. On a boe basis, royalties increased by 8% in the three months ended March 31, 2018 which is consistent with the 15% increase in commodity prices during the period.

The Company's average royalty rate decreased to 9.0% in the three months ended March 31, 2018 from 9.5% in the comparable period due to increased oil production from new drills in Saskatchewan that qualified for crown royalty incentives.

Operating Expenses

	Three months ended March 31, 2018	2017	Percent Change
Total operating expenses ($000's)	23,822	21,509	11
Percent of total revenue	17.5%	19.2%	(9)
Per boe ($)	10.97	10.50	4

During the three months ended March 31, 2018, operating expenses increased 11% to $23.8 million compared to $21.5 million in the same period of 2017. The increase in total operating expenses is primarily due to the 6% increase in production volumes.

Operating expenses averaged $10.97/boe in the first quarter of 2018, which represents an increase of 4% or $0.47/boe from $10.50/boe in the comparable period of 2017. Operating expenses per boe increased in 2018 compared to 2017 due to wellsite maintenance expenditures and increased general service and product costs.

Transportation Expenses

	Three months ended March 31, 2018	2017	Percent Change
Total transportation expenses ($000's)	3,061	2,970	3
Percent of total revenue	2.2%	2.7%	(19)
Per boe ($)	1.41	1.45	(3)

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased marginally to $3.1 million in the three months ended March 31, 2018, from $3 million in the comparable period of 2017 due to the 6% increase in production volumes. On a per boe basis, transportation expenses for the three months ended March 31, 2018 remained consistent at $1.41/boe from $1.45/boe in the comparable period of 2017.

General and Administrative ("G&A") Expenses

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
General and administrative	3,890	3,567	9
Overhead recoveries	(759)	(629)	21
Capitalized G & A	(850)	(843)	1
	2,281	2,095	9
Percent of total revenue	1.7%	1.9%	(11)
Per boe ($)	1.05	1.02	3

The Company incurred gross G&A expenses of $3.9 million in the three months ended March 31, 2018, an increase of 9% from $3.6 million in the comparable period of 2017. Increased G&A expenses before recoveries and capitalization were mainly a result of employee related costs, consulting fees and software fees, all of which are driven by the capital growth of the Company and its operations. Higher salary costs were driven by increased personnel including technical and operations staff. Capitalized G&A and overhead recoveries increased in the three months ended March 31, 2018, due to an increase in exploration and development expenditures.

Net general and administration expenses for the three months ended March 31, 2018, were $2.3 million or $1.05/boe compared to $2.1 million or $1.02/boe in the corresponding period of 2017. G&A per boe remained relatively consistent with the comparable period as the increase in G&A expenses were offset by higher production levels.

Financial Charges

	Three months ended March 31, 2018	2017	Percent Change
Financial charges ($000's)	2,771	2,028	37
Percent of total revenue	2.0%	1.8%	11
Per boe ($)	1.28	0.99	29

Financial charges for the three months ended March 31, 2018, were $2.8 million or $1.28/boe compared to $2 million or $0.99/boe in the comparable period of 2017. The Company's financial charges increased in the first quarter of 2018 from the comparable period of 2017, due to carrying higher average debt levels. Debt levels increased throughout the quarter to fund the significant 2018 capital expenditure program. The increase in financing charges is also attributable to the increase in standby fees charged as a result of an increase in the authorized borrowing base of our credit facilities to $500 million in the third quarter of 2017. As at March 31, 2018, the Company had drawn $254.6 million against the available credit facilities of $500 million.

Stock-based Compensation

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
Stock options	1,196	1,894	(37)
Share-based awards	1,448	1,009	44
Capitalized stock-based compensation	(607)	(611)	(1)
	2,037	2,292	(11)
Percent of total revenue	1.5%	2.0%	(25)
Per boe ($)	0.94	1.12	(16)

Stock-based compensation expense in the three months ended March 31, 2018, was $2 million, compared to $2.3 million for 2017. Stock-based compensation expense relating to stock options decreased in the first quarter ended March 31, 2018, as fewer stock options were granted in 2017 and no stock options were granted in the first quarter of 2018. Stock-based compensation relating to share-based awards increased in the first quarter ended March 31, 2018, due to additional amortization of share-based awards from new grants throughout 2018 and 2017.

Stock options

During the second quarter of 2016, the shareholders of the Company approved a new stock option plan ("New Option Plan"). Stock options that have been granted under the New Option Plan and the previous option plan ("Old Option Plan") have a term of 3.5 years to expiry and vest on each of the first, second, and third anniversaries from the date of grant. The stock-based compensation relating to options is accounted for using the fair value method of accounting. The expense associated with stock options is driven by the timing and valuation of stock option grants.

As at March 31, 2018, the Company had a total of 7,257,786 stock options outstanding with a weighted average fair value of $2.65 per stock option.

Share based awards

During the second quarter of 2016, the shareholders of the Company approved an incentive awards plan (the "Award Plan") consisting of restricted share units ("RSUs") and performance share units ("PSUs") whereby units may be granted to officers, employees and consultants of the Company. The maximum number of common shares issuable under the Award Plan shall not at any time exceed the lessor of: (i) 5% of the total common shares outstanding less the aggregate number reserved for issuance pursuant under the New Option Plan, and (ii) 6.5% of the total common shares outstanding less the aggregate number of common shares reserved for issuance pursuant to the New Option Plan and the Old Option Plan of the Company. Generally, one third of the RSUs will vest on each of the first, second and third anniversaries of the date of grant and all PSUs will vest on the third anniversary of the date of grant, unless otherwise determined by the board of directors of the Company. The common shares underlying PSUs are adjusted based on a payout multiplier ranging from 0 to 2 times, which is determined based on certain corporate performance measures, as determined by the board of directors of the Company, being met.

RSUs and PSUs are measured at fair value using the closing price of the common shares on the date of grant. The resulting stock-based compensation expense is recognized over the vesting period with the corresponding increase to contributed surplus. Upon vesting, the associated amount in contributed surplus is recorded as an increase to share capital. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of shares that vest.

As at March 31, 2018, the Company had 462,942 RSUs and 650,020 PSUs outstanding.

On April 4, 2016, the board of directors of the Company approved the adoption of the Deferred Share Units ("DSUs") plan. DSUs are granted to non-employee directors. Each DSU vests on the date of grant, however, settlement of the DSU occurs when the individual ceases to be a director of the Company. DSUs are to be settled in cash or by payment in common shares acquired through the facilities of the Toronto Stock Exchange ("TSX"). The directors may also elect to receive all of their annual cash compensation in the form of DSUs provided that such election must be made on December 1st of the preceding calendar year (or within certain prescribed time frame if an individual becomes a director after the commencement of a calendar year) and after such date the election will be irrevocable for such year. DSUs are measured at fair value using the closing trading price of the common shares on the date of grant.

As at March 31, 2018, the Company had 185,369 DSUs outstanding.

Depletion, Depreciation and Accretion

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
Depletion and depreciation	47,951	44,154	9
Exploration and evaluation lease expiries	5,148	3,085	67
Accretion	701	572	23
	53,800	47,811	13
Percent of total revenue	39.5%	42.7%	(7)
Per boe ($) – Depletion and depreciation	22.09	21.56	2
Per boe ($) – Exploration and evaluation lease expiries	2.37	1.51	57
Per boe ($) – Accretion	0.32	0.28	14

Depletion of oil and gas assets is provided on the "unit-of–production" method based on total proved and probable reserves, including future development costs, on a component basis. Depletion and depreciation expense during the three months ended March 31, 2018, were $48 million or $22.09/boe, compared to $44.2 million or $21.56/boe for the corresponding period in 2017. The increase in the depletion and depreciation expense is due to the increase in production volumes. Depletion per boe remained consistent in the first quarter of 2018 compared to 2017 as capital additions were offset by reserve additions.

Exploration and evaluation leases expiries of non-core land holdings for the three months ended March 31, 2018, were $5.1 million, compared to $3.1 million in the corresponding period of 2017. The majority of lease expiries occur in the first quarter of each year when Saskatchewan crown land leases come up for renewal.

Accretion increased in the three months ended March 31, 2018 to $701 thousand from $572 thousand in the comparable quarter of 2017. This increase is primarily due to the increase in asset retirement obligations from drilling activities. Accretion represents the time value of the asset retirement obligations and is calculated at the Company's risk-free rate, currently 2.3%. It will continue to increase with the passage of time and the increases in asset retirement obligations.

Asset Retirement Obligations

As at March 31, 2018, the asset retirement obligations of the Company were $131.2 million. The Company recorded an increase of $3.7 million from the asset retirement obligations of $127.5 million as at December 31, 2017. This is related to the capital exploration and development program in the first quarter of 2018 that was slightly offset by downward revision to the estimate. The revision to estimated asset retirement obligations of $1.6 million (December 31, 2017 - $6.5 million) in the period was due to discounting future cost estimates at a higher rate than in prior periods.

Income Taxes

The Company recorded a deferred income tax provision for the three months ended March 31, 2018 of $8.3 million compared to $6.4 million in the corresponding period. The Company's effective tax provision rate is 27%.

Raging River was not required to pay income taxes in the current period as the Company had sufficient income tax deductions available to shelter taxable income.

Funds Flow from Operations and Net Earnings

The Company's funds flow from operations and net earnings generating capability are a direct result of production, commodity prices, and the cost to find and produce reserves. In the three months ended March 31, 2018, Raging River recorded funds flow from operations of $89 million and net income of $21.7 million. This is a significant increase from the 2017 first quarter results with funds flow from operations of $72.8 million and net earnings of $15.3 million, due primarily to the increase in production volumes and commodity pricing that was partially offset by realized losses on commodity contracts, higher operating costs and increased financial charges.

The following table summarizes the operating netback, funds flow from operations and net earnings on a barrel of oil equivalent basis:

	Three months ended March 31, 2018	2017	Percent Change
	($/boe)		
Petroleum and natural gas revenue	62.80	54.70	15
Realized gain (loss) on risk management contracts (2)	(1.38)	0.13	(1,162)
Royalties	(5.64)	(5.22)	8
Net revenue	55.78	49.61	12
Operating expenses	(10.97)	(10.50)	4
Transportation expenses	(1.41)	(1.45)	(3)
Operating netback (1)	43.40	37.66	15
General and administrative expenses	(1.05)	(1.02)	3
Financial charges	(1.28)	(0.99)	29
Realized loss on risk management contracts (3)	(0.06)	-	(100)
Asset retirement expenditures	(0.02)	(0.12)	(83)
Funds flow netback (1)	40.99	35.53	15
Unrealized loss on risk management contracts	(1.44)	(0.57)	153
Stock-based compensation expense	(0.94)	(1.12)	(16)
Asset retirement expenditures	0.02	0.12	(83)
Depletion and depreciation expense	(22.09)	(21.56)	2
Exploration and evaluation lease expiries	(2.37)	(1.51)	57
Accretion expense	(0.32)	(0.28)	14
Earnings before deferred income taxes	13.85	10.61	31
Deferred income tax expense	(3.82)	(3.13)	22
Net earnings	10.03	7.48	34

(1) Non-GAAP measures. See Non-GAAP measures advisory.
(2) Includes realized loss on commodity contracts. Excludes realized loss on interest rate swap.
(3) Realized loss on interest rate swap.

Capital Expenditures

Total capital expenditures for the three months ended March 31, 2018, were $118.4 million, compared to $112.7 million for the corresponding period in 2017. The expenditures are detailed below:

	Three months ended March 31, 2018	2017	Percent Change
	(thousands of dollars)		
Land	5,566	6,186	(10)
Geological and geophysical	34	1	n/a
Drilling and completions	91,752	69,164	33
Facilities and equipping	21,049	37,330	(44)
Other	9	4	125
Total exploration and development	118,410	112,685	5

In the three months ended March 31, 2018, Raging River drilled a total of 128 (114.7 net) wells, with a 100% success rate. This included 126 (112.7 net) crude oil wells and 2 (2.0 net) injection wells. Of the 112.7 net wells drilled, 109.7 net wells were in the greater Dodsland area of southwest Saskatchewan and 3.0 net wells in the Duvernay light oil play in central Alberta. By comparison, the Company drilled a total of 104 (99.5 net) wells in the comparable period of 2017 with a 99% success rate.

In the three months ended March 31, 2018, the Company invested a total of $118.4 million on capital expenditures including $112.8 million on drilling, completions and production facilities and $5.6 million on land and geological and geophysical costs.

The Company is maintaining a 2018 capital expenditure budget of $335 million. Raging River has allocated $254 million to drilling, completions and equipping of Viking horizontal wells, $43.5 million to the development of the Duvernay light oil play, $16.5 million to waterflood and gas conservation and the remaining $21 million to land, seismic and maintenance capital. This budget will be funded from anticipated 2018 cash flow combined with the Company's existing credit facilities of $500 million.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended March 31, 2018		2017	
	Gross	Net	Gross	Net
Crude oil	126	112.7	98	93.5
Natural gas	-	-	-	-
Service/Injection	2	2.0	5	5.0
Dry and abandoned	-	-	1	1.0
Total	128	114.7	104	99.5
Success	100%	100%	99%	99%

Liquidity and Capital Resources

At March 31, 2018, the Company had net debt of $329 million compared to net debt of $299.6 million at December 31, 2017. For the three months ended March 31, 2018, funds flow from operations of $89 million less capital expenditures of $118.4 million resulted in the ending net debt of $329 million. The Company expects to have adequate liquidity to fund the remainder of its 2018 capital expenditure budget of $335 million through a combination of funds flow from operations and the $500 million syndicated credit facilities. Raging River anticipates that it will make use of additional bank debt or equity financing for any substantial expansion in its capital program or to finance any significant acquisitions.

The Company's credit facilities consist of a $450 million extendible revolving credit facility with a syndicate of lenders and a $50 million extendible operating credit facility. The credit facilities have a revolving period currently expiring on April 25, 2019, extendible annually at the request of the Company, subject to approval of the lenders, and repayable one year after the expiry of the revolving period. The credit facilities are secured by a first floating charge debenture in the amount of $1 billion over all of the Company's assets and bear interest at rates that fluctuate, depending on the Company's debt to EBITDA ratio (as defined in the agreement governing the credit facilities). Repayments of principal are not required until the maturity date, provided that the borrowings under the credit facilities do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties under the credit facilities. As at March 31, 2018 and the date hereof, the Company is in compliance with all covenants under the credit facilities. The borrowing base of the credit facilities is subject to a semi-annual redetermination on or before April 30 and October 31 of each year.

Capital Resources

	March 31, 2018	2017
($ thousands)		
Capital Resources		
Bank debt available	500,000	400,000
Net debt	(329,040)	(249,475)
	170,960	150,525

Changes to share capital in 2018 were the following:

During the three months ended March 31, 2018, 166 thousand stock options were exercised for 31 thousand common shares on a cash-less basis.

Common share information

CAPITALIZATION

Share Capital

	March 31, 2018	2017
Weighted average outstanding common shares [(1)]		
-Basic	231,298,802	231,152,138
-Diluted	231,660,461	231,500,832
Outstanding securities at March 31, 2018		
-Common shares		231,302,556
-Stock options – average strike price of $8.98		7,257,786
-Restricted share units		462,942
-Performance share units		650,020
-Deferred share units		185,369

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted profit per common share.

Total Market Capitalization

The Company's market capitalization at March 31, 2018 was approximately $1.4 billion.

	March 31, 2018
Common shares outstanding	231,302,556
Share price [(1)]	$6.24
Total market capitalization	$1,443,327,949

(1) Represents the last price traded on the TSX on March 29, 2018.

As at May 14, 2018 the Company had 231,302,556 common shares outstanding.

	May 14, 2018
Outstanding securities at May 14, 2018	
-Common shares	231,302,556
-Stock options – weighted average exercise price of $8.98	7,230,121
-Restricted share units	460,542
-Performance share units	650,020
-Deferred share units	185,369

Contractual Obligations and Commitments

Raging River has assumed various contractual obligations and commitments in the normal course of operations and financing activities. We consider these obligations when assessing cash requirements in the discussion of future liquidity. As at March 31, 2018, the Company was committed to the future minimum payments as follows:

($ thousands)	2018	2019	2020	2021	Thereafter	Total
Accounts payable	135,569	-	-	-	-	135,569
Office lease	802	746	99	99	197	1,943
Risk management contracts	9,591	-	-	-	-	9,591
Bank debt	-	254,644	-	-	-	254,644
Transportation and processing	8,724	14,327	12,526	9,415	53,557	98,549
Total contractual obligations and commitments	154,686	269,717	12,625	9,514	53,754	500,296

Off-Balance Sheet Arrangements

There are currently no significant off-balance sheet arrangements.

Related Party Transactions

The Company did not have any related party transactions in the three months ended March 31, 2018.

Summary of Quarterly Results

	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	136,312	130,167	102,987	105,982	112,017	98,479	80,632	67,528
Funds flow from operations (1)(8)	88,964	83,867	60,407	64,965	72,752	64,561	49,726	43,999
Per share - basic	0.38	0.36	0.26	0.28	0.31	0.28	0.22	0.19
- diluted	0.38	0.36	0.26	0.28	0.31	0.28	0.22	0.19
Net earnings	21,737	19,950	5,929	18,595	15,343	18,986	6,758	5,320
Per share - basic	0.09	0.09	0.03	0.08	0.07	0.08	0.03	0.02
- diluted	0.09	0.09	0.03	0.08	0.07	0.08	0.03	0.02
Capital expenditures, net	118,410	74,554	116,196	68,640	112,685	134,917	120,179	63,727
Net debt (4)	329,040	299,594	308,906	253,117	249,475	209,543	140,187	63,101
Shareholders' equity	993,603	969,222	946,708	938,337	917,366	899,120	877,442	826,775
Weighted average shares (thousands)								
Basic	231,299	231,266	231,249	231,178	231,152	231,114	230,227	226,231
Diluted	231,660	231,566	231,386	231,335	231,501	232,048	231,154	227,167
Shares outstanding, end of period *(thousands)*								
Basic	231,303	231,271	231,250	231,243	231,156	231,142	231,039	226,600
Diluted	232,416	233,253	232,804	232,979	236,603	239,961	240,434	235,878
Operating *(6:1 boe conversion)*								
Average daily production								
Light oil and NGLs *(bbls/d)*	21,351	20,891	20,271	18,795	19,476	17,058	15,643	14,603
Heavy oil *(bbls/d)*	1,146	1,115	1,135	1,189	1,419	1,780	1,738	171
Natural gas *(mcf/d)*	9,722	10,020	9,627	12,185	11,161	9,652	7,385	7,368
Barrels of oil equivalent (2) *(boe/d)*	24,118	23,676	23,011	22,015	22,755	20,447	18,612	16,002
Average selling prices (4)								
Light oil and NGLs *($/bbl)*	67.68	64.25	51.95	57.35	59.16	56.56	50.78	49.68
Heavy oil *(bbls/d)*	43.75	52.15	45.90	45.75	44.35	43.51	37.66	31.10
Natural gas *($/mcf)*	1.99	1.44	1.48	2.66	2.64	2.91	2.06	1.10
Barrels of oil equivalent (2) *($/boe)*	62.80	59.76	48.65	52.90	54.70	52.35	47.09	46.37
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	62.80	59.76	48.65	52.90	54.70	52.35	47.09	46.37
Realized gain (loss) on risk management contracts (6)	(1.38)	(0.70)	0.04	(0.37)	0.13	(0.15)	(0.05)	0.11
Royalties	(5.64)	(5.52)	(4.52)	(5.05)	(5.22)	(4.94)	(4.55)	(4.54)
Operating expenses	(10.97)	(11.02)	(11.02)	(11.31)	(10.50)	(10.79)	(10.15)	(8.98)
Transportation expenses	(1.41)	(1.39)	(1.43)	(1.41)	(1.45)	(1.42)	(1.46)	(1.39)
Operating netback *($/boe)* (5)(8)	43.40	41.13	31.72	34.76	37.66	35.05	30.88	31.57
General and administrative	(1.05)	(1.09)	(1.09)	(1.05)	(1.02)	(1.00)	(1.15)	(1.20)
Financial charges	(1.28)	(1.38)	(1.15)	(1.14)	(0.99)	(0.82)	(0.63)	(0.46)
Realized loss on risk management contracts (7)	(0.06)	(0.06)	-	-	-	-	-	-
Asset retirement obligation	(0.02)	(0.10)	(0.03)	(0.15)	(0.12)	(0.12)	(0.05)	(0.04)
Current tax (expense) recovery	-	-	(0.92)	-	-	1.22	-	0.34
Funds flow netback (3)(8) *($/boe)*	40.99	38.50	28.53	32.42	35.53	34.33	29.05	30.21

(1) Management uses funds flow from operations to analyze operating performance and leverage. Funds flow from operations as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities. The reconciliation between funds flow from operations and cash flow from operating activities can be found in this MD&A.

(2) Boe conversion ratio for natural gas of 1 Boe: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

(3) Funds flow netbacks are calculated as the operating netback less general and administrative expenses, financial charges, realized gains (losses) on the interest rate swap, asset retirement obligations, and current taxes or recovery.
(4) Excludes unrealized risk management contracts.
(5) Operating netback is calculated as revenues received less royalties, operating and transportation costs and realized gains or losses on commodity contracts.
(6) Includes realized loss on commodity contracts. Excludes realized loss on interest rate swap.
(7) Realized loss on interest rate swap.
(8) Non-GAAP measure. See "Non-GAAP Measures" advisory

The fluctuations in Raging River's revenue, funds flow from operations and net earnings from quarter to quarter are primarily due to increases in production volumes, changes in realized commodity pricing and the related impact on royalties. With the commencement of operations in the latter part of the first quarter of 2012, and continuing through into 2018, the Company has maintained an active capital expenditure program combined with property acquisitions and corporate acquisitions. This has resulted in a steady increase on a quarter over quarter basis in the Company's production. Revenues, funds flow from operations and net earnings have fluctuated throughout 2017 due to volatile commodity pricing. In the first quarter of 2018, the increase in commodity pricing combined with increase in production levels, resulted in the increase of revenue, funds flow from operations and net earnings. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the first quarter of 2018.

Business Environment and Risk

The business risks the Company is exposed to are those inherent in the oil and gas industry as well as those governed by the individual nature of Raging River's operations. Geological and engineering risks, the uncertainty of discovering commercial quantities of new reserves, commodity prices, interest rate and foreign exchange risks, competition and government regulations – all of these govern the business and influence the controls and management at the Company. Raging River manages these risks by:

- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Company;
- operating properties in order to maximize opportunities;
- employing risk management instruments to minimize exposure to volatility of commodity prices, interest rate and foreign exchange rates;
- maintaining a strong financial position; and
- maintaining strict environmental, safety and health practices.

For additional details on the risks relating to Raging River's business, see "Risk Factors" in the Company's most recent annual information form for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com.

Disclosure Controls and Procedures

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") of the Company have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109") of the Canadian Securities Administrators, to provide reasonable assurance that: (i) information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and the CFO of Raging River have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR") as defined in NI 52-109. The control framework Raging River's officers used to design the Company's ICFR is the COSO Framework published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The CEO and CFO have concluded that the Company's ICFR were effective as of December 31, 2017. There have been no changes in the ICFR during the period from January 1, 2018 to March 31, 2018 that have materially affected or are reasonably likely to materially affect the Company's ICFR.

It should be noted that while Raging River's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect that these controls will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Application of Critical Accounting Estimates

Use of estimates and judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

Estimates and their underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected.

a) Critical Judgments in Applying Accounting Policies

Determination of cash-generating units ("CGU") and impairment

The determination of what constitutes a CGU used to test the recoverability of development and production asset carrying values is subject to management judgment. Judgments are made in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality. The asset composition of a CGU can directly impact the recoverability of the assets included therein. The key estimates used in the determination of cash flows from oil and natural gas reserves include the following:

i) Reserves – assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production levels or results of future drilling may change the economic viability of reserves and may ultimately result in reserves being restated.

ii) Oil and natural gas prices – forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors.

iii) Discount rate – the discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

Exploration and evaluation ("E&E") assets

The application of the Company's accounting policy for E&E assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found. Judgment is also required to determine the level at which E&E is assessed for impairment; for Raging River, the recoverable amount of E&E assets is assessed at the CGU level.

Deferred income taxes

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting year will be realized from future taxable earnings.

b) Key Sources of Estimation Uncertainty

Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed, which includes assessing the value of oil and natural gas properties based on the estimation of recoverable quantities of proved plus probable reserves being acquired.

Valuation of property and equipment/Reserves

The valuation of property and equipment involves the estimation of proved plus probable reserves and includes assumptions regarding future commodity prices, exchange rates, discount rates, future development costs and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the asset retirement obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property and equipment. These reserve estimates are evaluated by third-party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument (NI) 51-101, "Standards of Disclosure for Oil and Gas Activities". Accordingly, the impact to the financial statements in future years could be material.

Asset retirement obligations

Amounts recorded for asset retirement obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of abandonment expenditures. Other provisions are recognized in the year when it becomes probable that there will be a future cash outflow.

Valuation of derivative financial instruments

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature are subject to measurement uncertainty.

Measurement of share-based compensation

The estimated fair value of stock options uses pricing models such as the Black-Scholes model which is based on significant assumptions such as volatility, forfeiture rates and the expected term. The fair value of RSUs, PSUs and DSUs is estimated based on the closing price of the common shares on the day of grant. Judgement is required to estimate the number of RSUs and PSUs that will ultimately vest.

Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Summary of Significant Accounting Policies

The Company's accounting policies are described in Note 3 to the December 31, 2017 audited annual financial statements. In the current period, the Company adopted the following changes to IFRS:

IFRS 9: Financial Instruments

As of January 1, 2018, the Company adopted all of the requirements of IFRS 9 Financial Instruments.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL"). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments and the contractual cash flow characteristics of the financial assets. Most of the requirements in IAS 39 for classification and measurement of financial liabilities were carried forward in IFRS 9. IFRS 9 has introduced a single expected credit loss impairment model, which is based on changes in credit quality since initial recognition. The adoption of the expected credit loss impairment model did not have any impact on the financial statements of the Company, however there are additional required disclosures which have been included in note 12 of the March 31, 2018 interim financial statements. Accounts receivable, accounts payable and bank debt are classified and measured at amortized cost. Risk management contacts are classified and measured at FVTPL. The Company does not have any asset contracts and debt investments measured at FVOCI.

IFRS 9 also contains a new hedge accounting model, however the Company does not apply hedge accounting to any of its risk management contracts.

The adoption of IFRS 9 has been applied retrospectively and did not result in a change in the carrying value of any of the Company's financial instruments on the transition date.

IFRS 15: Revenue from Contacts with Customers

As of January 1, 2018, the Company adopted all of the requirements of IFRS 15 Revenue from Contacts with Customers. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 13 in the March 31, 2018 interim financial statements.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. The Company recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if the Company acts in the capacity of an agent rather than as a principal.

Revenue from the sale of heavy crude oil, light crude oil, natural gas and natural gas liquids is based on the consideration specified in contracts from customers. The Company recognizes revenue when it transfers control of the product to the buyer. This is generally at the time product enters a third-party pipeline or when the delivery truck arrives at a customer's receiving location.

The transaction price for variable price contracts is based on a benchmark commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of crude oil or natural gas transferred to customers.

Future accounting pronouncements and accounting standards issued but not yet effective:

IFRS 16 Leases, which replaces IAS 17 Leases was issued in January 2016. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. Management is currently assessing the potential impact of the adoption of IFRS 16 on the Company's financial statements.

Non-GAAP Measures

The MD&A contains the term funds flow from operations which should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash necessary to fund capital investments and to repay debt. The reconciliation between cash flow from operating activities and funds flow from operations is presented before the change in non-cash operating working capital. The Company reconciles funds flow from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

	Three months ended March 31, 2018	2017
	(thousands of dollars)	
Cash flow from operating activities	81,067	79,261
Changes in non – cash working capital	7,897	(6,509)
Funds flow from operations	88,964	72,752

The Company presents funds flow from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share.

The MD&A contains other terms such as net debt, operating netbacks and funds flow netbacks, which are not recognized measures under IFRS. Management believes these measures are useful supplemental measures of: the total amount of current and long-term debt the Company has; the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs; and the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs, general and administrative expenses, financial charges, asset retirement expenditures and current taxes, respectively. Net debt represents current assets less current liabilities and bank debt and is used to assess efficiency, liquidity and the general financial strength of the Company. Mark-to-market risk management contracts are excluded from the net debt calculation. Readers are cautioned however, that these measures should not be construed as an alternative to other terms such as current and long-term debt or net earnings in accordance with IFRS as measures of performance. The Company's method of calculating these measures may differ from other companies, and accordingly, such measures may not be comparable to measures used by other companies.

The following table reconciles long-term debt (a GAAP measure) to net debt (a non-GAAP measure):

	March 31, 2018	December 31, 2017
	(thousands of dollars)	
Long-term debt	254,644	248,732
Current liabilities	145,160	113,546
Current assets	(61,617)	(56,673)
Risk management contracts liability	(9,591)	(6,209)
Risk management contracts assets	444	198
Net debt	329,040	299,594

Oil and Gas Metrics

Barrels of Oil Equivalent

The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Per boe amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. This equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward Looking Statements

This Management's Discussion and Analysis ("MD&A") may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, the expected amount of the Company's 2018 capital expenditure budget, the expectation that the 2018 capital budget is expected to be funded from a combination of anticipated 2018 cash flow combined with availability under the Company's credit facilities, the expectation that Raging River will make use of additional bank debt or equity financing for any substantial expansion in its capital program or to finance any significant acquisitions. When used in this document, the words "anticipate", "believe", "estimate", "expect", "intent", "may", "project", "plan", "should" and similar expressions are intended to be among the statements that identify forward-looking statements. Forward-looking statements are subject to a wide range of risks and uncertainties, and although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will be realized. The forward-looking statements contained herein are based on certain key expectations and assumptions made by the Company, including but not limited to expectations and assumptions with respect to the availability of capital, current legislation, pipeline capacity, receipt of required regulatory approval, the success of future drilling and development activities, the performance of existing wells, the performance of new wells, Raging River's growth strategy, general economic conditions, availability of required equipment and services and the costs of obtaining such equipment and services, and prevailing commodity prices. Any number of important factors could cause actual results to differ materially from those in the forward-looking *statements, including, but not limited to, risks associated with petroleum and natural gas, exploration, development, exploitation, production, marketing and transportation, the volatility of petroleum and natural gas prices, currency fluctuations, the ability to implement corporate strategies, the state of domestic capital markets, the ability to obtain financing, incorrect assessments of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in petroleum and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from other producers, imprecision or reserve estimates, labour supply risks, environmental risks, competition from other producers, changes in general economic conditions, whether farm-in and farm-out opportunities result in agreements and other factions more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities including the Company's most recent annual information form. To the extent that any forward-looking information contained herein may be considered future oriented financial information or a financial outlook, such information has been included to provide readers with an understanding of management's assumptions used for budgeting and developing future plans and readers are cautioned that the information may not be appropriate for other purposes. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. Readers are cautioned not to place undue reliance on forward-looking statements, as no assurances can be given as to future results, levels of activity or achievements. Except as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements.*

Corporate Information

Board of Directors

NEIL ROSZELL
Executive Chairman & CEO, Raging River Exploration Inc.
Calgary, Alberta

BRUCE BEYNON
President, Raging River Exploration Inc.
Calgary, Alberta

GARY BUGEAUD (2)
Businessman
Calgary, Alberta

GEORGE FINK (1) (2) (3)
Chairman & CEO, Bonterra Energy Corp.
Calgary, Alberta

RAYMOND P. MACK (1)
Partner, Kenway Mack Slusarchuk Stewart LLP
Calgary, Alberta

KEVIN OLSON (1) (3)
President, Kyklopes Capital Management Ltd.
Calgary, Alberta

DAVE PEARCE (2) (3)
Deputy Managing Partner, Azimuth Capital Management
Calgary, Alberta

(1) Audit Committee
(2) Compensation and Corporate Governance Committee
(3) Reserves Committee

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Officers

NEIL ROSZELL, P. Eng.
Executive Chairman & CEO

BRUCE BEYNON
President

JERRY SAPIEHA, CA
Vice President Finance & CFO

JASON JASKELA
Vice President Production and COO

JESSE BARLOW
Vice President Engineering

TERRY DANKU
Vice President Exploitation

JON GRIMWOOD
Vice President Exploration

CHAD LUNDBERG
Vice President Operations

SCOTT RIDEOUT
Vice President Land

TED BROWN (Corporate Secretary)
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