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 March 5, 2018 and should be read in conjunction with the audited financial statements for the years ended December 31, 2017 and 2016 and the notes thereto. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars. In addition, readers are also directed to the Company's Annual Information Form for the year ended December 31, 2017, dated March 5, 2018, filed on SEDAR at www.sedar.com.

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.

FOURTH QUARTER 2017 HIGHLIGHTS

- Achieved a quarterly production record with average production of 23,676 boe/d (93% oil) representing an increase of 16% over the comparable period in 2016. This represents a 16% production per share increase from the fourth quarter of 2016.
- Achieved funds flow from operations of $83.9 million ($0.36/share basic), a 39% increase quarter over quarter and a 30% increase from the fourth quarter of 2016.
- The Company generated operating netbacks of $41.83/boe on an unhedged basis and funds flow netbacks of $38.50/boe.
- Generated fourth quarter net earnings of $20 million or $9.17/boe.
- Corporate royalties continued to be stable at 9.2% during the quarter.
- The Company's exploration and development expenditures for the quarter were $74.6 million. A total of 48.9 net Viking crude oil wells were drilled at a 96% success rate.
- As previously reported, our initial Duvernay light oil discovery well was successfully drilled and completed in the fourth quarter.
- Maintained balance sheet strength with year-end net debt of $299.6 million representing 0.9 times net debt to fourth quarter annualized funds flow from operations.

YEAR ENDED DECEMBER 31, 2017

- Production averaged 22,867 boe/d, a 28% increase (25% production per share) from 2016 annual production of 17,900 boe/d.

- Generated corporate funds flow from operations of $282 million ($1.22/share basic) a significant increase of 50% from 2016.

- Attained top decile general and administrative costs of $1.06/boe, a 7% decrease from 2016.

- Executed a $372.1 million exploration and development program to drill a total of 328.8 net Viking crude oil wells and 1.0 net Duvernay well for a success rate of 98%. The capital expenditures consisted of $297.4 million of Viking development capital, $31.9 million of capital deployed into long term Viking waterflood initiatives as well as $42.8 million into early stage land capture and initial evaluation of an emerging Duvernay light oil play.

- Proved plus probable reserves increased 14% to 106.7 mmboe (94% oil) and proved reserves increased 15% to 82 mmboe (94% oil).

- Finding and development costs including the change in future development capital were:
  - $36.95 per boe on a proved developed producing basis resulting in a recycle ratio of 1.0 times.
  - $28.77/boe on a total proved basis resulting in a recycle ratio of 1.3 times.
  - $25.11/boe on a total proved plus probable basis resulting in a recycle ratio of 1.5 times.

- Total net undeveloped land holdings increased 38% to 591,363 acres. The 38% increase in undeveloped land was primarily in the Duvernay shale basin where the Company now holds approximately 250,000 acres.

- Increased our credit facilities to $500 million from $400 million in July 2017.

Petroleum and Natural Gas Operations

Production and Pricing

	Three months ended December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
Average daily production						
Light oil and liquids (bbls/d)	20,891	17,058	22	19,863	15,589	27
Heavy oil (bbls/d)	1,115	1,780	(37)	1,213	965	26
Natural gas (mcf/d)	10,020	9,652	4	10,742	8,079	33
Barrels of oil equivalent (boe/d)	23,676	20,447	16	22,867	17,900	28
Raging River average sales price						
Light oil and liquids ($/bbl)	64.25	56.56	14	58.23	48.56	20
Heavy oil ($/bbl)	52.15	43.51	20	46.86	39.29	19
Natural gas ($/mcf)	1.44	2.91	(51)	2.10	2.06	2
Barrel of oil equivalent ($/boe)	59.76	52.35	14	54.05	45.34	19
Average Benchmark Prices						
Crude oil - WTI (US$/bbl)	55.40	49.29	12	50.95	43.32	18
Crude oil – MSW (Cdn$/bbl)	68.94	61.59	12	62.82	52.90	19
Crude oil – WCS (Cdn$/bbl)	54.85	46.61	18	50.51	38.88	30
Natural gas – AECO (Cdn$/mcf)	1.72	3.11	(45)	2.20	2.18	1
Exchange rate (US$/Cdn$)	0.786	0.750	5	0.771	0.755	2

Revenues

	Three months ended December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Light oil and liquids	123,135	88,635	39	421,420	276,677	52
Heavy oil	5,349	7,126	(25)	20,755	13,882	50
Natural gas	1,328	2,588	(49)	8,244	6,084	36
Royalty	355	130	173	734	377	95
	130,167	98,479	32	451,153	297,020	52

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 December 31, 2017, the West Texas Intermediate ("WTI") price increased 12% quarter over quarter, resulting in an increase in the Company's realized crude oil price. The Company's light crude oil price averaged $64.25/bbl for the fourth quarter of 2017, an increase of 14% from $56.56/bbl in the fourth quarter of 2016. Raging River's average quality adjustment to MSW pricing of $4.69/bbl in the fourth quarter of 2017 was consistent with the fourth quarter of 2016. 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.

In the year ended December 31, 2017, the 18% increase in the WTI price, resulted in a higher realized light crude oil price for the Company. Raging River's light crude oil price averaged $58.23/bbl in the year ended December 31, 2017, an increase of 20% from the average price of $48.56/bbl received in the comparable period of 2016. Raging River's average quality adjustment to MSW pricing slightly increased in the year ended December 31, 2017 to $4.59/bbl from $4.34/bbl in the comparable period of 2016.

The Company's heavy crude oil price averaged $52.15/bbl for the fourth quarter of 2017, a significant increase of 20% from $43.51/bbl in the fourth quarter of 2016. The average quality adjustment to WCS pricing of $2.70/bbl narrowed in the fourth quarter 2017 compared to $3.10/bbl in the fourth quarter of 2016. This is consistent with the strengthening of the WCS price differential to the WTI price in the fourth quarter of 2017 from the comparable period in 2016. The Company's heavy crude oil price averaged $46.86/bbl in the year ended December 31, 2017, an increase of 19% from the average price of $39.29/bbl received in the comparable period of 2016. For the year ended December 31, 2016, the heavy oil realized price reflects the increased heavy oil weighting at higher realized prices in the second half of the year, as a result of the acquisition with Rock Energy Inc. that closed in July 2016.

The AECO natural gas price experienced high volatility throughout 2017. Natural gas pricing declined significantly in the fourth quarter of 2017 due to the continued increase in storage levels and transportation constraints in western Canada. This infrastructure bottleneck resulted in a decline in natural gas pricing and a decrease in the natural gas price realized by the Company. Raging River's realized natural gas price for the fourth quarter of 2017 was $1.44 per mcf compared to $2.91 per mcf in the comparable period.

For the year ended December 31, 2017, Raging River's realized natural gas price was $2.10 per mcf, an increase of 2 percent compared to the same period in 2016, consistent with the increase in the benchmark natural gas pricing over the same periods.

Drilling and Production

During the fourth quarter of 2017, the Company drilled a total of 63 (52.9 net) wells resulting in 58 (47.9 net) crude oil wells, 3 (3.0 net) injection wells and 2 (2.0 net) dry holes, for a success rate of 96%. In the year ended December 31, 2017, Raging River drilled a total of 379 (338.8 net) wells resulting in 363 (322.8 net) crude oil wells, 9 (9.0 net) injection wells and 7 (7.0 net) dry holes for an overall success rate of 98%.

Production	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15
Light oil and liquids (bbls/d)	20,891	20,271	18,795	19,476	17,058	15,643	14,603	15,034	14,021
Heavy oil (bbls/d)	1,115	1,135	1,189	1,419	1,780	1,738	171	154	173
Natural gas (mcf/d)	10,020	9,629	12,185	11,161	9,652	7,385	7,368	7,900	3,461
Total (boe/d)	23,676	23,011	22,015	22,755	20,447	18,612	16,002	16,505	14,771
% increase (decrease) over prior quarter	3%	5%	(3%)	11%	10%	16%	(3%)	12%	10%
Production per 1 million shares	102.4	99.5	95.2	98.5	88.5	80.8	70.7	76.2	72.8
Per share % increase (decrease) over prior quarter	3%	5%	(3%)	11%	10%	14%	(7%)	5%	8%

The Company's production for the fourth quarter of 2017 increased to 23,676 boe/d from 20,447 boe/d in the fourth quarter of 2016, an increase of 16%. Quarter over quarter, production in the fourth quarter of 2017, increased 3% to 23,676 boe/d from 23,011 boe/d in the third quarter of 2017. The year over year increase of 28% was primarily attributable to a successful drilling program in 2017.

Petroleum and natural gas revenue in the three month period December 31, 2017 was $130.2 million as compared to $98.5 million in the corresponding period of 2016. This increase was attributable to a 16% increase in production volumes combined with a 14% increase in commodity pricing.

Petroleum and natural gas revenues for the year ended December 31, 2017 were $451.2 million, as compared to $297 million in the corresponding period of 2016, representing an increase of 52%. This increase in revenue is attributed to a 28% increase in production volumes and a 19% 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 December 31, 2017, 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 5, 2018:

Contract Type	Type	Term	Volume	Fixed Contract Price	Index
Crude oil	Fixed	Jan 2018 - Dec 2018	2,750 bbl/d	Cdn $68.29	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 December 31, 2017, Raging River has the following interest rate swap contract outstanding:

Contract Type	Notional Amount	Reference Price	Fixed Contract Price	Maturity date
Interest rate Swap	$100,000,000	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 December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Realized loss – commodity contracts	(1,530)	(279)	448	(1,904)	(10)	18,940
Realized loss – interest rate swap	(124)	-	100	(124)	-	100
Realized loss on risk management contracts	(1,654)	(279)	493	(2,028)	(10)	20,180
Unrealized gain (loss) – commodity contracts	(5,537)	374	(1,580)	(5,833)	(592)	(885)
Unrealized gain - interest rate swap	198	-	100	198	-	100
Unrealized gain (loss) on risk management contracts	(5,339)	374	(1,528)	(5,635)	(592)	(852)

The realized gain/loss represents the risk management contracts settled during fourth quarter and year ended December 31, 2017. 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 December 31, 2017, the Company incurred a realized loss of $1.5 million compared to $0.3 million in the corresponding period of 2016 on commodity contracts. The Company had crude oil commodity contracts to fix the differential between the WTI and Edmonton SW - Blended price at Cdn$4.47/bbl and US$2.97/bbl. The actual differentials were Cdn$1.46/bbl and US$1.15/bbl, resulting in a realized loss. This tightening of the differentials in the fourth quarter of 2017 was primarily due to scheduled oil sands maintenance that took production off the market, resulting in stronger demand for light sweet oil. This was partially offset by the realized gain recognized on natural gas contracts. The Company had natural gas commodity contracts to fix the AECO index price at an average of Cdn$3.06/GJ, which exceeded the AECO settlement price of Cdn$1.75/GJ.

For the year ended December 31, 2017, the Company recorded a $1.9 million realized loss compared to a realized loss of $10 thousand in the corresponding period of 2016. The Company recognized losses on its crude oil contacts, as the commodity contacts to fix the differential between WTI and the Edmonton SW-blended price exceeded the actual differentials in the period. This was partially offset by the gain realized on natural gas commodity contracts due to the fixed AECO contracted price exceeding the AECO settlement price.

For the fourth quarter and year ended December 31, 2017, realized losses of $0.1 million were 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 December 31, 2017, the fair value of Raging River's outstanding risk management contracts is an unrealized liability of $6.2 million and an asset of $0.2 million as reflected in the annual 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 December 31, 2017, 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 December 31, 2017.

Royalties

	Three months ended December 31, 2017	Three months ended December 31, 2016	Percent Change	Year ended December 31, 2017	Year ended December 31, 2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	2,359	1,967	20	9,110	5,895	55
Saskatchewan resource surcharge	2,045	1,748	17	6,940	5,421	28
Freehold and GORR	7,618	5,581	36	26,355	17,291	52
	12,022	9,296	29	42,405	28,607	48
Percent of total revenue	9.2%	9.4%	(2)	9.4%	9.6%	(2)
Per boe ($)	5.52	4.94	12	5.08	4.37	16

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and the Saskatchewan resource surcharge. Royalties increased to $12 million in the fourth quarter of 2017 from $9.3 million in the fourth quarter of 2016, primarily as a result of a 16% increase in production volumes. On a boe basis, royalties increased by 12% in the fourth quarter which is consistent with the 14% increase in commodity prices during the period.

During the year ended December 31, 2017, royalties increased 48% to $42.4 million from $28.6 million in the comparable period. The increase is primarily a result of a 28% increase in production volumes and a 19% increase in average realized prices in 2017.

The Company’s royalty rates were consistent in the fourth quarter and year ended December 31, 2017, at 9.2% and 9.4% million respectively, compared to 9.4% and 9.6% in the corresponding periods of 2016.

Operating Expenses

	Three months ended December 31, 2017	Three months ended December 31, 2016	Percent Change	Year ended December 31, 2017	Year ended December 31, 2016	Percent Change
Total operating expenses ($000’s)	24,000	20,297	18	91,482	64,200	42
Percent of total revenue	18.4%	20.6%	(11)	20.3%	21.6%	(6)
Per boe ($)	11.02	10.79	2	10.96	9.80	12

During the three months ended December 31, 2017, operating expenses increased 18% to $24 million compared to $20.3 million in the same period of 2016. During the year ended December 31, 2017, operating expenses increased 42% to $91.5 million compared to $64.2 million in 2016. The increase in total operating expenses is primarily due to the increase (16% and 28%, respectively) in production volumes in both the fourth quarter and year ended December 31, 2017.

Operating expenses averaged $11.02/boe in the fourth quarter of 2017 and $10.96/boe in the year to date. This represents an increase of 2% or $0.23/boe from $10.79/boe in the fourth quarter of 2016 and an increase of 12% or $1.16/boe from $9.80/boe in the year ended December 31, 2016. Operating expenses per boe increased in 2017 compared to 2016 due to wellsite maintenance expenditures and increased general service and product costs. Ongoing facility capital expenditures are expected to positively impact the operating cost structure in 2018.

Transportation Expenses

	Three months ended December 31, 2017	Three months ended December 31, 2016	Percent Change	Year ended December 31, 2017	Year ended December 31, 2016	Percent Change
Total transportation costs ($000's)	3,031	2,666	14	11,851	9,250	28
Percent of total revenue	2.3%	2.7%	(15)	2.6%	3.1%	(16)
Per boe ($)	1.39	1.42	(2)	1.42	1.41	1

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased to $3 million in the fourth quarter of 2017 from $2.7 million in the fourth quarter of 2016, due to the 16% increase in production volumes. During the year ended December 31, 2017, transportation costs increased 28% to $11.9 million from $9.3 million in the comparable period due to the 28% increase in production volumes.

Transportation costs averaged $1.39/boe in the fourth quarter of 2017 and $1.42/boe in the year to date. This represents a decrease of 2% from $1.42/boe in the fourth quarter of 2016 and an increase of 1% from $1.41/boe in the year ended December 31, 2016.

General and Administrative ("G&A") Expenses

	Three months ended December 31, 2017	Three months ended December 31, 2016	Percent Change	Year ended December 31, 2017	Year ended December 31, 2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	3,943	3,383	17	15,610	11,856	32
Overhead recoveries	(630)	(577)	9	(2,980)	(1,389)	115
Capitalized G&A	(944)	(934)	1	(3,767)	(2,985)	26
	2,369	1,872	27	8,863	7,482	18
Percent of total revenue	1.8%	1.9%	(5)	2.0%	2.5%	(20)
Per boe ($)	1.09	1.00	9	1.06	1.14	(7)

The Company incurred gross G&A expenses of $3.9 million and $15.6 million, respectively, during the fourth quarter and year ended December 31, 2017. Increased G&A expenses before recoveries and capitalization were mainly a result of employee related costs, office rent, 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, operations and administrative staff. Capitalized

G&A and overhead recoveries increased in both the fourth quarter and year ended December 31, 2017, due to a substantial increase in exploration and development expenditures.

Net G&A expenses incurred were $2.4 million or $1.09 per boe and $8.9 million or $1.06 per boe, respectively, during the fourth quarter and year ended December 31, 2017. G&A per boe remained relatively consistent with the comparable periods as the increase in G&A expenses were offset by higher production levels.

Financial Charges

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2017	2016		2017	2016	
Financial charges ($000's)	3,015	1,550	95	9,776	4,530	116
Percent of total revenue	2.3%	1.6%	44	2.2%	1.5%	47
Per boe ($)	1.38	0.82	68	1.17	0.69	70

Financial charges during the fourth quarter and year ended December 31, 2017, were $3.0 million and $9.8 million respectively, compared to $1.6 million and $4.5 million in the corresponding periods of 2016. The Company's financial charges increased in both the fourth quarter and year ended December 31, 2017 from the comparable periods of 2016, due to carrying higher average debt levels. Debt levels increased throughout 2017 to fund the significant 2017 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 to $500 million in the third quarter of 2017. As at December 31, 2017, the Company had drawn $248.7 million against the available credit facilities of $500 million.

In the fourth quarter of 2017, Raging River's borrowing base was reviewed and the syndicate of lenders underwriting the Company's credit facilities confirmed the Company's borrowing facility to $500 million. The next borrowing base redetermination is scheduled for April 2018.

Stock-based Compensation

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2017	2016		2017	2016	
	(thousands of dollars)			*(thousands of dollars)*		
Stock options	1,436	1,972	(27)	6,227	7,960	(22)
Share-based awards	1,127	748	51	4,026	1,769	128
Capitalized stock-based compensation	(727)	(661)	10	(2,479)	(2,330)	6
Stock-based compensation expense	1,836	2,059	(11)	7,774	7,399	5
Percent of total revenue	1.4%	2.1%	(33)	1.7%	2.5%	(32)
Per boe ($)	0.84	1.09	(23)	0.93	1.13	(18)

Stock-based compensation expense during the fourth quarter and year ended December 31, 2017, was $1.8 million and $7.8 million respectively, compared to $2.1 million and $7.4 million in the corresponding periods of 2016. Stock-based compensation expense relating to stock options decreased in both the fourth quarter and year ended December 31, 2017, as the fair value of new grants is lower than in previous periods and fewer stock options were granted in 2017. Stock-based compensation relating to share based awards increased in both the fourth quarter and year ended December 31, 2017, due to additional amortization of share based awards from new grants throughout 2016 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 December 31, 2017, the Company had a total of 7.8 million (December 31, 2016 – 9.4 million) stock options outstanding with a weighted average fair value of $2.62 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 stock 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 December 31, 2017, the Company had 469,662 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 on the date of grant.

As at December 31, 2017, the Company had 131,824 DSUs outstanding.

Depletion, Depreciation and Accretion

	Three months ended December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	47,813	39,360	21	182,505	142,571	28
Exploration and evaluation lease expiries	458	160	186	4,598	3,152	46
Accretion	680	453	50	2,469	1,540	60
	48,951	39,973	23	189,572	147,263	29
Percent of total revenue	37.6%	40.6%	(7)	42.0%	49.6%	(15)
Per boe ($) – Depletion and depreciation	21.95	20.92	5	21.87	21.76	1
Per boe ($) – Exploration and evaluation lease expiries	0.21	0.08	163	0.55	0.48	15
Per boe ($) - Accretion	0.31	0.24	29	0.30	0.24	25

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 fourth quarter and year ended December 31, 2017, were $47.8 million and $182.5 million respectively, compared to $39.4 million and $142.6 million for the corresponding periods in 2016. The increase in the depletion and depreciation expense in both the fourth quarter and year ended December 31, 2017, is due to the increase in production volumes.

Depletion per boe remained consistent in both the fourth quarter of 2017 and the year ended December 31, 2017 compared to 2016, as significant capital additions from drilling activities were offset by significant reserve additions. Total proved plus probable reserves grew to 106.7 million boe, a 14% increase over the December 31, 2016 reserves of 94 million boe. Future development costs of $968.4 million have been included in the capital base used in the calculation and salvage values of $55.2 million have been excluded in the calculation.

Exploration and evaluation leases expiries of non-core land holdings for the fourth quarter and year ended December 31, 2017, were $0.5 million and $4.6 million, respectively, compared to $0.2 million and $3.2 million in the corresponding periods of 2016. The majority of lease expiries occur in the first quarter of each year when Saskatchewan crown land leases come up for renewal.

Accretion expense for the fourth quarter and year ended December 31, 2017, was $0.7 million and $2.5 million, respectively, compared to $0.5 million and $1.5 million in the corresponding periods of 2016. This increase is primarily due to the increase in asset retirement obligation from drilling activities. Accretion represents the time value of the asset retirement obligation and is calculated at the Company’s risk-free rate, currently 2.2%. It will continue to increase with the passage of time and the increases in asset retirement obligations.

Asset Retirement Obligations

As at December 31, 2017, the asset retirement obligation of the Company was $127.5 million. The Company recorded an increase of $29.7 million in the obligation from the asset retirement obligation of $97.8 million as at December 31, 2016. This is related to the capital exploration and development program in 2017 and an upward revision to the estimate. The revision to estimated asset retirement obligations of $6.5 million (December 31, 2016 - $3.4 million) in the year was due to discounting future cost estimates at a lower rate than in prior periods.

Income Taxes

During the fourth quarter and year ended December 31, 2017, the Company recorded a deferred income tax provision of $8 million and $20 million respectively, compared to $8.5 million and $14.5 million in the corresponding periods of 2016. The Company's effective tax provision rate is 27%.

The Company recorded current tax expense of $1.95 million in year ended December 31, 2017, due to a change in estimates relating to a corporate acquisition in the prior period. This prior period adjustment in the respective 2017 period resulted in a partial reversal of the 2016 current tax recovery accrual. Based on current commodity strip prices, the Company does not expect to pay cash taxes in 2017 and 2018. The Company recorded a current tax recovery of $5.7 million in the year ended December 31, 2016.

The Company's tax pools are estimated to be approximately $1.0 billion as of December 31, 2017, up 11% from $921.5 million at December 31, 2016. The federal tax pools are estimated as follows:

($ thousands)	Estimated balance at January 1, 2018
Canadian oil and gas property expense	252,263
Canadian development expense	457,223
Canadian exploration expense	13,561
Undepreciated capital cost	242,457
Non-capital losses	48,541
Share issue costs and other	7,505
Total	1,021,550

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 year ended December 31, 2017, Raging River recorded funds flow from operations of $282 million and net income of $59.8 million. This is a significant increase from the comparable 2016 results with funds flow from operations of $188.2 million and a net earnings of $23.2 million, due primarily to the significant increase in production volumes and commodity pricing that was partially offset by 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 December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
	($/boe)			($/boe)		
Petroleum and natural gas revenue	59.76	52.35	14	54.05	45.34	19
Realized loss on risk management contracts [2]	(0.70)	(0.15)	367	(0.23)	-	100
Royalties	(5.52)	(4.94)	12	(5.08)	(4.37)	16
Net revenue	53.54	47.26	13	48.74	40.97	19
Operating expenses	(11.02)	(10.79)	2	(10.96)	(9.80)	12
Transportation expenses	(1.39)	(1.42)	(2)	(1.42)	(1.41)	1
Operating netback [1]	41.13	35.05	17	36.36	29.76	22
General and administrative expenses	(1.09)	(1.00)	9	(1.06)	(1.14)	(7)
Financial charges	(1.38)	(0.82)	68	(1.17)	(0.69)	70
Realized loss on risk management contracts [3]	(0.06)	-	100	(0.01)	-	100
Asset retirement expenditures	(0.10)	(0.12)	(17)	(0.10)	(0.07)	43
Current taxes (expense) recovery	-	1.22	(100)	(0.23)	0.87	(126)
Funds flow netback [1]	38.50	34.33	12	33.79	28.73	18
Unrealized gain (loss) on risk management contracts	(2.45)	0.20	n/a	(0.68)	(0.09)	656
Stock-based compensation expense	(0.84)	(1.09)	(23)	(0.93)	(1.13)	(18)
Gain on acquisition	-	2.30	(100)	-	0.66	(100)
Asset retirement expenditures	0.10	0.12	(17)	0.10	0.07	43
Depletion and depreciation expense	(21.95)	(20.92)	5	(21.87)	(21.76)	1
Exploration and evaluation lease expiries	(0.21)	(0.08)	163	(0.55)	(0.48)	15
Accretion expense	(0.31)	(0.24)	29	(0.30)	(0.24)	25
Earnings before deferred income taxes	12.84	14.62	(12)	9.56	5.76	66
Deferred income tax expense	(3.67)	(4.52)	(19)	(2.40)	(2.21)	9
Net earnings	9.17	10.10	(9)	7.16	3.55	102

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

Capital Expenditures

Total capital expenditures for the fourth quarter and year ended December 31, 2017, were $74.6 million and $372.1 million respectively, compared to $134.9 million and $403.2 million for the corresponding periods in 2016. The expenditures are detailed below:

	Three months ended December 31, 2017	2016	Percent Change	Year ended December 31, 2017	2016	Percent Change
	(thousands of dollars)			(thousands of dollars)		
Land	6,277	1,325	374	33,799	4,424	664
Geological and geophysical	18	44	(59)	68	82	(17)
Drilling and completions	50,837	61,115	(17)	243,805	160,691	52
Facilities and equipping	17,360	14,160	23	94,291	46,261	104
Other	62	14	343	110	98	12
Exploration and development	74,554	76,658	(3)	372,073	211,556	76
Property acquisitions	-	58,259	(100)	-	83,384	(100)
Corporate acquisitions [1]	-	-	-	-	108,308	(100)
Total invested capital	74,554	134,917	(45)	372,073	403,248	(8)

(1) Raging River acquired Rock Energy Inc. in July 2016 (the "Rock Acquisition"). The total cost of the Rock Acquisition includes $41.1 million of common share consideration (based on approximately 3.9 million Raging River common shares being issued and a closing price on the date of the Rock Acquisition of $10.56 per common share of Raging River) and $67.2 million of net debt assumed.

Exploration and development capital

In the year ended December 31, 2017, Raging River drilled a total of 378 (337.8 net) wells primarily in the greater Dodsland area in southwest Saskatchewan and 1 net Duvernay well, with a 98% success rate. This included 363 (322.8 net) crude oil wells, 9 (9.0 net) injection wells and 7 (7.0 net) dry holes. By comparison, the Company drilled a total of 311 (281.5 net) wells in the year ended December 31, 2016 with a 100% success rate.

In the quarter ended December 31, 2017, the Company invested a total of $74.6 million on capital expenditures including $68.3 million on drilling, completing, and equipping activities and $6.3 million on land and geological and geophysical costs.

During the year ended December 31, 2017, the Company spent $372.1 million on capital expenditures including $338.2 million on drilling, completions and production facilities and $33.9 million on land, and geological and geophysical costs.

2018 capital budget

The Company's board of directors have approved the 2018 exploration and development budget of $335 million. Raging River has allocated $254 million to Viking drilling, completions and equipping, $43.5 million to Duvernay drilling, completions and equipping, $16.5 million to facilities, waterflood and gas conservation and the remaining $21 million to land, seismic and maintenance capital. This budget is expected to be funded from anticipated 2017 funds flow from operations combined with the Company's existing credit facilities of $500 million.

Land Holdings

We have evaluated our undeveloped land holdings internally. This internal evaluation estimated the fair market value of our 591,363 net acres of undeveloped land holdings as at December 31, 2017, at $237 million. For purposes of the internal evaluation "fair market value" is defined as the price which we believe could be reasonably expected to be received for the undeveloped lands in an arm's length transaction. In order to determine fair market value, we considered a number of factors including a) current prices being paid for crown lands in the same area b) terms and conditions, expressed in monetary terms of recent farm-in and/or work commitments and the degree of exploration activity in each area, and c) recent industry sales of similar properties in the same general area. In areas where current prices or other pertinent information was not available, we used our best judgment.

During 2017, Raging River significantly increased its undeveloped land base, primarily targeting the Duvernay oil play. In 2017, a total of approximately 243,000 net acres of undeveloped land were acquired through land sales and minor property acquisitions. The following table summarizes our developed and undeveloped land holdings (in acres) as at December 31, 2017.

	Undeveloped		Developed		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Saskatchewan	320,431	282,598	119,776	105,272	440,207	387,870
Alberta	337,841	308,573	44,317	23,756	382,158	332,329
British Columbia	548	192	2,806	1,164	3,354	1,356
Total	658,820	591,363	166,899	130,192	825,719	721,555

(1) *"Gross" means the total number of acres in which we hold an interest.*
(2) *"Net" means the total area in which Raging River has an interest multiplied by Raging River's working interest.*

Drilling Activity

The following table summarizes our drilling results:

	Three months ended December 31,				Year ended December 31,			
	2017		2016		2017		2016	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	58	47.9	121	106.1	363	322.8	302	272.5
Natural gas	-	-	-	-	-	-	-	-
Service/Injection	3	3.0	6	6.0	9	9.0	8	8.0
Dry and abandoned	2	2.0	-	-	7	7.0	1	1.0
Total	63	52.9	127	112.1	379	338.8	311	281.5
Success	97%	96%	100%	100%	98%	98%	100%	100%

Liquidity and Capital Resources

At December 31, 2017, the Company had net debt of $299.6 million compared to net debt of $209.5 million at December 31, 2016. For the year ended December 31, 2017, funds flow from operations of $282 million less capital expenditures of $372.1 million resulted in the ending net debt of $299.6 million. The Company expects to have adequate liquidity to fund the 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 26, 2018, 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 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

	December 31, 2017	December 31, 2016
($ thousands)		
Capital Resources		
Bank debt available	500,000	400,000
Net debt	(299,594)	(209,543)
	200,406	190,457

Changes to share capital in 2017 were the following:

During the year ended December 31, 2017, 83.3 thousand common shares were released from treasury to settle the vesting of 83.3 thousand restricted and performance share units.

During the year ended December 31, 2017, 180 thousand stock options were exercised for 41 thousand common shares on a cash-less basis and 5 thousand stock options were exercised for 5 thousand common shares for proceeds of $32 thousand.

Common share information

CAPITALIZATION

Share Capital

	Three months ended December 31,		Year ended December 31,	
	2017	2016	2017	2016
Weighted average outstanding common shares (1)				
-Basic	231,266	231,114	231,210	225,946
-Diluted	231,566	232,048	231,506	226,533
Outstanding securities at December 31, 2017				
-Common shares				231,271,492
-Stock options – average strike price of $8.98				7,835,112
-Restricted share units				469,692
-Performance share units				650,020
-Deferred share units				131,824

(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 December 31, 2017 was approximately $1.9 billion.

	December 31, 2017
Common shares outstanding	231,271,492
Share price (1)	$8.00
Total market capitalization	$1,850,171,936

(1) Represents the last price traded on the TSX on December 29, 2017.

As at March 5, 2018 the Company had 231,302,556 common shares outstanding.

	March 5, 2018
Outstanding securities at March 5, 2018	
-Common shares	231,302,556
-Stock options – weighted average exercise price of $8.98	7,261,785
-Restricted share units	462,942
-Performance share units	650,020
-Deferred share units	172,449

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 December 31, 2017, the Company was committed to the future minimum payments as follows:

($ thousands)	2018	2019	2020	2021	Thereafter	Total
Accounts payable	107,337	-	-	-	-	107,337
Office lease	1,069	746	99	99	197	2,210
Risk management contracts	6,209	-	-	-	-	6,209
Bank debt	-	248,732	-	-	-	248,732
Transportation and processing	8,088	13,762	12,488	9,397	53,557	97,292
Total contractual obligations and commitments	122,703	263,240	12,587	9,496	53,754	461,780

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 year ended December 31, 2017.

Selected Annual Information

The following table summarizes key annual financial and operating information over the most recently completed financial years.

	2017	2016	2015
Financial *(thousands of dollars except share data and production volumes)*			
Average production volumes (boe/d)	22,867	17,900	13,715
Petroleum and natural gas revenue	451,153	297,020	254,932
Funds flow from operations (1)	281,991	188,188	167,351
Per share - basic	1.22	0.83	0.85
- diluted	1.22	0.83	0.84
Net earnings	59,817	23,212	28,919
Per share - basic	0.26	0.10	0.15
- diluted	0.26	0.10	0.15
Total assets	1,545,606	1,327,732	1,029,034
Long-term debt	248,732	168,194	108,897
Net debt(1)	299,594	209,543	139,943
Weighted average shares *(thousands)*			
Basic	231,210	225,946	197,701
Diluted	231,506	226,533	198,601

(1) Funds flow from operations and net debt do not have a standardized meaning under GAAP. Refer to non-GAAP measures in this MD&A.

Summary of Quarterly Results

	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	130,167	102,987	105,982	112,017	98,479	80,632	67,528	50,382
Funds flow from operations (1)	83,867	60,407	64,965	72,752	64,561	49,726	43,999	29,904
Per share - basic	0.36	0.26	0.28	0.31	0.28	0.22	0.19	0.14
- diluted	0.36	0.26	0.28	0.31	0.28	0.22	0.19	0.14
Net earnings	19,950	5,929	18,595	15,343	18,986	6,758	5,320	(7,852)
Per share - basic	0.09	0.03	0.08	0.07	0.08	0.03	0.02	(0.04)
- diluted	0.09	0.03	0.08	0.07	0.08	0.03	0.02	(0.04)
Capital expenditures, net	74,554	116,196	68,640	112,685	134,917	120,179	63,727	37,380
Net debt(4) (6)	299,594	308,906	253,117	249,475	209,543	140,187	63,101	44,564
Shareholders' equity	969,222	946,708	938,337	917,366	899,120	877,442	826,775	817,839
Weighted average shares (thousands)								
Basic	231,266	231,249	231,178	231,152	231,114	230,227	226,231	216,493
Diluted	231,566	231,386	231,335	231,501	232,048	231,154	227,167	216,493
Shares outstanding, end of period *(thousands)*								
Basic	231,271	231,250	231,243	231,156	231,142	231,039	226,600	226,014
Diluted	233,253	232,804	232,979	236,603	239,961	240,434	235,878	232,741
Operating *(6:1 boe conversion)*								
Average daily production								
Light oil and NGLs *(bbls/d)*	20,891	20,271	18,795	19,476	17,058	15,643	14,603	15,034
Heavy oil *(bbls/d)*	1,115	1,135	1,189	1,419	1,780	1,738	171	154
Natural gas *(mcf/d)*	10,020	9,627	12,185	11,161	9,652	7,385	7,368	7,900
Barrels of oil equivalent (2) *(boe/d)*	23,676	23,011	22,015	22,755	20,447	18,612	16,002	16,505
Average selling prices(4)								
Light oil and NGLs *($/bbl)*	64.25	51.95	57.35	59.16	56.56	50.78	49.68	35.47
Heavy oil *(bbls/d)*	52.15	45.90	45.75	44.35	43.51	37.66	31.10	17.84
Natural gas *($/mcf)*	1.44	1.48	2.66	2.64	2.91	2.06	1.10	1.89
Barrels of oil equivalent (2) *($/boe)*	59.76	48.65	52.90	54.70	52.35	47.09	46.37	33.54
Netbacks ($/boe)								

Operating								
Petroleum and natural gas revenue(4)	59.76	48.65	52.90	54.70	52.35	47.09	46.37	33.54
Realized gain (loss) on risk management contracts (6)	(0.70)	0.04	(0.37)	0.13	(0.15)	(0.05)	0.11	0.14
Royalties	(5.52)	(4.52)	(5.05)	(5.22)	(4.94)	(4.55)	(4.54)	(3.27)
Operating expenses	(11.02)	(11.02)	(11.31)	(10.50)	(10.79)	(10.15)	(8.98)	(8.95)
Transportation expenses	(1.39)	(1.43)	(1.41)	(1.45)	(1.42)	(1.46)	(1.39)	(1.37)
Operating netback *($/boe)*(5)	41.13	31.72	34.76	37.66	35.05	30.88	31.57	20.09
General and administrative	(1.09)	(1.09)	(1.05)	(1.02)	(1.00)	(1.15)	(1.20)	(1.26)
Financial charges	(1.38)	(1.15)	(1.14)	(0.99)	(0.82)	(0.63)	(0.46)	(0.82)
Realized loss on risk management contracts (7)	(0.06)	-	-	-	-	-	-	-
Asset retirement obligation	(0.10)	(0.03)	(0.15)	(0.12)	(0.12)	(0.05)	(0.04)	(0.03)
Current tax (expense) recovery	-	(0.92)	-	-	1.22	-	0.34	1.93
Funds flow netback(3) *($/boe)*	38.50	28.53	32.42	35.53	34.33	29.05	30.21	19.91

(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, 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 losses on commodity contracts. Excludes realized losses on interest rate swap.
(7) Includes realized losses on interest rate swap.

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 2017, the Company has maintained an active capital expenditure program combined with property acquisitions and corporate acquisitions. This has resulted in a substantial increase on a quarter over quarter basis in the Company's production. Revenues, funds flow from operations and net earnings have fluctuated throughout 2016 and 2017 due to volatile commodity pricing. In the fourth quarter of 2017, 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 fourth quarter of 2017.

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, 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.

The CEO and the CFO have evaluated the effectiveness of Raging River's disclosure controls and procedures as at December 31, 2017 and have concluded that such disclosure controls and procedures were effective as at such date.

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, 2017 to December 31, 2017 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.

Future accounting pronouncements and accounting standards issued but not yet effective

IFRS 15 Revenue from Contracts with Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Raging River on January 1, 2018. The impact of the standard has been evaluated and is expected to have no material impact on the Company's financial statements. Additional disclosures will be required upon implementation in order to provide sufficient information to enable users to understand the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers.

IFRS 9 Financial Instruments, is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and 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. For financial liabilities designated at fair value through profit or loss, a company can recognize the portion of the change in fair value related to the change in the company's own credit risk through other comprehensive income rather than in earnings. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Company has determined there will not be any material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. Additional disclosure for financial instruments will be required.

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 December 31,		Year ended, December 31,	
	2017	2016	2017	2016
	(thousands of dollars)			
Cash flow from operating activities	81,844	60,063	286,889	173,898
Changes in non – cash working capital	2,023	4,498	(4,898)	14,290
Funds flow from operations	83,867	64,561	281,991	188,188

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):

	December 31, 2017	December 31, 2016
	(thousands of dollars)	
Long-term debt	248,732	168,194
Current liabilities	113,546	95,918
Current assets	(56,673)	(54,192)
Risk management contracts liability	(6,209)	(377)
Risk management contracts asset	198	-
Net debt	299,594	209,543

<u>Oil and Gas Metrics</u>

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.

Finding and Development Costs and Recycle Ratio

This MD&A contains a number of oil and gas metrics, including finding and development costs and recycle ratio, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the Company's future performance. Finding and development costs include exploration and development capital costs for that period plus the change in future development capital for that period. This capital including the change in the future development capital is then divided by the change in reserves categorized for development for that period incorporating all revisions and production for that same period. The recycle ratio was calculated by dividing operating netback per boe by the finding, development and acquisition costs for the year.

Forward Looking Statements

This Management Discussion and Analysis ("MD&A") may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, expected operating costs, the expectation that ongoing facility capital expenditures are expected to positively impact the operating cost structure in 2018, details of the 2018 capital budget including expected capital expenditures, 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 the Company will not have to pay cash taxes in 2017 and 2018, 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 concerning including but not limited to expectations and assumptions with respect to the success of optimization and efficiency improvement projects, 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, imprecision of reserve estimates, changes in general economic conditions, whether farm-in and farm-out opportunities result in agreements and other factors 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. Statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. To the extent any forward looking statements herein constitute a financial outlook, they are included herein to provide readers with an understanding of management's plans and assumptions for budgeting purposes 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

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Vice President Land

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