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 6, 2017 and should be read in conjunction with the audited financial statements for the years ended December 31, 2016 and 2015 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, 2016, dated March 6, 2017, filed on SEDAR at www.sedar.com.

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 royalty rates, expected transportation costs, details of the 2017 capital budget including expected capital expenditures, expectations that the Company will have adequate liquidity to fund operations and capital expenditures and the timing and funding thereof. 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. 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.

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. The reconciliation between cash flow from operating activities and funds flow from operations can be found in the statement of cash flows in the annual financial statements and 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,	
	2016	2015	2016	2015
	(thousands of dollars)			
Cash flow from operating activities	60,063	38,549	173,898	138,228
Changes in non – cash working capital	4,498	2,159	14,290	29,123
Funds flow from operations	64,561	40,708	188,188	167,351

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.

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.

Finding Development & Acquisition Costs, Finding and Development Costs and Recycle Ratio

This MD&A contains a number of oil and gas metrics, including finding, development and acquisition costs, 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, development and acquisition costs and finding and development costs are used as a measure of capital efficiency. The finding, development and acquisition cost calculation includes all capital costs (exploration, development and acquisition capital) for that period plus the change in future development capital for that period. This total capital including

the change in the future development capital is then divided by the change in reserves for that period incorporating all revisions and production for that same period. 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.

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 oil resource play in western Canada, being primarily located in the Dodsland area in southwestern Saskatchewan and southeast Alberta.

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 2016 HIGHLIGHTS

- Achieved a quarterly production record with average production of 20,447 boe/d (92% oil) representing an increase of 38% over the comparable period in 2015. This represents a 22% production per share increase from the fourth quarter of 2015.

- Achieved funds flow from operations of $64.6 million ($0.28/share basic), an increase of 59% from the fourth quarter of 2015.

- Generated fourth quarter net earnings of $19 million or $10.10 per boe, an increase of 168% from the fourth quarter of 2015 on a boe basis.

- The Company's exploration and development expenditures for the quarter were $76.7 million. A total of 106.1 net Viking crude oil wells were drilled at a 100% success rate.

- Closed a Dodsland Viking property acquisition for cash consideration of $58.3 million. The Company acquired approximately 620 boe/d (97% light oil) of production and 24 net sections of land prospective for Viking light oil.

- Maintained balance sheet strength with year-end net debt of $209.5 million representing 0.8 times net debt to fourth quarter annualized funds flow from operations.

- Increased our credit facilities to $400 million from $300 million in December 2016.

YEAR ENDED DECEMBER 31, 2016

- Production averaged 17,900 boe/d, a 31% increase (21% per share) from 2015 annual production of 13,715 boe/d.

- Generated corporate funds flow from operations of $188.2 million ($0.83/share basic) an increase of 12% from 2015.

- Attained top decile general and administrative costs of $1.14/boe, a 12% decrease from 2015.

- Raging River continued to add to its drilling inventory through strategic corporate and property acquisitions. The Company invested a total of $403.2 million consisting of $191.6 million of acquisition capital that expanded the Viking play and $211.6 million of development capital.

- Completed the $108.3 million corporate acquisition of Rock Energy Inc. ("Rock Acquisition"). The Rock Acquisition included 2,550 boe/d (95% oil) of production and approximately 25 net sections of highly prospective land targeting Viking light oil in the Kerrobert area of southwest Saskatchewan.

- Completed two property acquisitions for total cash consideration of $83.4 million, to further consolidate the Company's interests in the Viking light oil fairway.

- Executed a $211.6 million exploration and development program to drill a total of 303 (273.5 net) Viking crude oil wells with a 99.6% success rate.

- Proved plus probable reserves increased 23% to 94 mmboe (94% oil) and proved reserves increased 25% to 71.6 mmboe (94% oil).

- Finding, development and acquisition costs including the change in future development capital were:
  - $26.86 per boe on a proved developed producing basis resulting in a recycle ratio of 1.1 times.
  - $23.54/boe on a total proved basis resulting in a recycle ratio of 1.3 times.
  - $19.42/boe on a total proved plus probable basis resulting in a recycle ratio of 1.5 times.

- Finding and development costs including the change in future development capital were:
  - $22.04 per boe on a proved developed producing basis resulting in a recycle ratio of 1.4 times.
  - $22.16/boe on a total proved basis resulting in a recycle ratio of 1.3 times.
  - $16.83/boe on a total proved plus probable basis resulting in a recycle ratio of 1.8 times.

- Total net undeveloped land holdings increased 53% to 428,100 acres principally in our core Viking prospect areas in southwest Saskatchewan and southeast Alberta.

- During 2016, the Company completed a bought deal financing for gross proceeds of approximately $108.1 million, issuing 12.5 million common shares at a price of $8.65 per common share.

Petroleum and Natural Gas Operations

Production and Pricing

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2016	2015	Change	2016	2015	Change
Operating: (6:1 boe conversion)						
Average daily production						
Light oil and liquids (bbls/d)	17,058	14,021	22	15,589	13,051	19
Heavy oil (bbls/d)	1,780	173	929	965	184	424
Natural gas (mcf/d)	9,652	3,461	179	8,079	2,877	181
Barrels of oil equivalent (boe/d)	20,447	14,771	38	17,900	13,715	31
Raging River average sales price						
Light oil and liquids ($/bbl)	56.56	47.83	18	48.56	52.38	(7)
Heavy oil ($/bbl)	43.51	31.82	37	39.29	40.26	(2)
Natural gas ($/mcf)	2.91	2.31	26	2.06	2.59	(20)
Barrel of oil equivalent ($/boe)	52.35	46.32	13	45.34	50.93	(11)
Average Benchmark Prices						
Crude oil - WTI (US$/bbl)	49.29	42.18	17	43.32	48.80	(11)
Crude oil – MSW (Cdn$/bbl)	61.59	52.87	16	52.90	57.14	(7)
Crude oil – WCS (Cdn$/bbl)	46.61	36.87	26	38.88	44.82	(13)
Natural gas – AECO (Cdn$/mcf)	3.11	2.48	25	2.18	2.70	(19)
Exchange rate (US$/Cdn$)	0.75	0.75	-	0.76	0.78	(3)

Revenues

	Three months ended December 31, 2016	Three months ended December 31, 2015	Percent Change	Year ended December 31, 2016	Year ended December 31, 2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Light oil and liquids revenue	88,635	61,623	44	276,677	249,198	11
Heavy oil revenue	7,126	506	1308	13,882	2,701	414
Natural gas revenue	2,588	736	252	6,084	2,719	124
Royalty revenue	130	78	67	377	314	20
	98,479	62,943	56	297,020	254,932	17

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, 2016, the West Texas Intermediate ("WTI") price increased 17% quarter over quarter, resulting in an increase in the Company's realized crude oil price. The Company's light crude oil price averaged $56.56/bbl for the fourth quarter of 2016, an increase of 18% from $47.83/bbl in the fourth quarter of 2015. The average quality adjustment to MSW pricing of $5.03/bbl in the fourth quarter was consistent with the fourth quarter of 2015. Raging River's quality adjustments are related to our average oil being 35° API versus the 40° API WTI benchmark, yielding an approximate $5/bbl differential to MSW.

In the year ended December 31, 2016, the decline in the WTI, only partially offset by a weak Canadian dollar resulted in a lower realized light crude oil price for the Company. Raging River's light crude oil price averaged $48.56/bbl in the year ended December 31, 2016, down 7% from the average price of $52.38/bbl received in the comparable period of 2015. Raging River's average quality adjustment to MSW pricing slightly decreased in the year ended December 31, 2016 to $4.34/bbl from $4.76/bbl in the comparable period of 2015.

The Company's heavy crude oil price averaged $43.51/bbl for the fourth quarter of 2016, an increase 37% from $31.82/bbl in the fourth quarter of 2015. The Company's heavy crude oil price averaged $39.29/bbl in the year ended December 31, 2016, down 2% from the average price of $40.26/bbl received in the comparable period of 2015. 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 Rock acquisition that closed in July 2016.

The average AECO prices declined on a year over year basis due to above average input into storage from an oversupplied market and warmer weather reducing demand, resulting in downward pressure on natural gas pricing and a decrease in the natural gas price realized by the Company. In the fourth quarter of 2016, colder than normal weather was experienced, resulting in a 25% increase in AECO pricing and an increase in the natural gas prices realized by the Company. Raging River's realized natural gas price in the fourth quarter and year ended December 31, 2016 was $2.91 per mcf and $2.06 per mcf respectively, compared to $2.31 per mcf and $2.59 per mcf for the same periods in 2015.

Drilling

During the fourth quarter of 2016, the Company drilled a total of 127 (112.1 net) wells resulting in 121 (106.1 net) crude oil wells and 6 (6.0 net) service wells, with a 100% success rate. In the year ended December 31, 2016, Raging River drilled a total of 311 (281.5 net) wells resulting in 302 (272.5 net) crude oil wells, 8 (8.0 net) service wells and 1 (1.0 net) dry hole for an overall success rate of 99.6%.

Average Production	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14
Light oil and liquids (bbls/d)	17,058	15,643	14,603	15,034	14,021	12,805	12,664	12,704	11,675
Heavy oil (bbls/d)	1,780	1,738	171	154	173	204	192	166	384
Natural gas (mcf/d)	9,652	7,385	7,368	7,900	3,461	2,454	2,947	2,641	2,931
Total (boe/d)	20,447	18,612	16,002	16,505	14,771	13,418	13,347	13,310	12,548
% increase over prior quarter	10%	16%	(3%)	12%	10%	1%	-	6%	18%
Production per 1 million shares	88.5	80.8	70.7	76.2	72.8	67.2	67.4	70.0	69.6
Per share % increase (decrease) over prior quarter	10%	14%	(7%)	5%	8%	-	(4%)	1%	17%

The Company's production for the fourth quarter of 2016 increased to 20,447 boe/d from 14,771 boe/d in the fourth quarter of 2015, an increase of 38%. Quarter over quarter, production in the fourth quarter of 2016, increased 10% to 20,447 boe/d from 18,612 boe/d in the third quarter of 2016. The year over year increase of 38% was primarily attributable to a successful drilling program in 2015 and 2016 combined with the strategic property and corporate acquisitions. The Rock Acquisition that closed on July 21, 2016, contributed additional production volumes of approximately 1,100 boe/d in 2016. The Dodsland Viking property acquisition that closed late in the fourth quarter of 2016, had an immaterial impact to 2016 production levels.

Petroleum and natural gas revenue in the three month period December 31, 2016 was $98.5 million as compared to $62.9 million in the corresponding period of 2015. This increase was attributable to a 38% increase in production volumes and a 13% increase in commodity pricing.

Petroleum and natural gas revenues for the year ended December 31, 2016 were $297 million, as compared to $254.9 million in the corresponding period of 2015, representing an increase of 17%. This increase in revenue is attributed to a 31% increase in production volumes that was partially offset by an 11% decrease in commodity pricing.

Commodity Price Risk Management

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 managment 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. As of March 6, 2017 the Company has the following price contracts in place by quarter:

2017

Q1					
Crude oil	Differential	Jan 2017 – Mar 2017	2,000 bbls/d	Cdn $4.25/bbl	WTI/Edm
Crude oil	Differential	Jan 2017 – Mar 2017	3,333 bbls/d	US $2.98/bbl	WTI/Edm
Natural gas	Fixed	Jan 2017 – Mar 2017	3,000 GJs/d	Cdn $3.05/GJ	AECO
Q2					
Crude oil	Differential	Apr 2017 – Jun 2017	3,000 bbls/d	Cdn $4.12/bbl	WTI/Edm
Crude oil	Differential	Apr 2017 – Jun 2017	6,000 bbls/d	US $2.97/bbl	WTI/Edm
Natural gas	Fixed	Apr 2017 – Jun 2017	2,500 GJs/d	Cdn $3.06/GJ	AECO
Q3					
Crude oil	Differential	Jul 2017 – Sept 2017	2,000 bbls/d	Cdn $4.47/bbl	WTI/Edm
Crude oil	Differential	Jul 2017 – Sept 2017	6,000 bbls/d	US $2.97/bbl	WTI/Edm
Natural gas	Fixed	Jul 2017 – Sept 2017	2,500 GJs/d	Cdn $3.06/GJ	AECO
Q4					
Crude oil	Differential	Oct 2017 – Dec 2017	2,000 bbls/d	Cdn $4.47/bbl	WTI/Edm
Crude oil	Differential	Oct 2017 – Dec 2017	6,000 bbls/d	US $2.97/bbl	WTI/Edm
Natural gas	Fixed	Oct 2017 – Dec 2017	2,500 GJs/d	Cdn $3.06/GJ	AECO

Realized & Unrealized Gain/Loss on Commodity Contracts

The realized gain/loss represents the commodity contracts settled during fourth quarter and year ended December 31, 2016. As the 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 daily and monthly index.

For the three month period ended December 31, 2016, the Company incurred a realized loss of $278.9 thousand (three months ended December 31, 2015 - realized gains of $1.2 million). The Company realized losses on crude oil differential commodity contracts. The Company also realized losses on natural gas hedges due to an increase in the AECO price in the period.

For the year ended December 31, 2016, the Company recorded a $10 thousand realized loss (year ended December 31, 2015 - realized gain of $4.6 million). The Company realized gains on natural gas commodity contracts due to the decline in the AECO price throughout 2016. This was offset by losses recognized on crude oil commodity contracts, as the differential between WTI and the Edmonton SW blended price narrowed in the year.

As of December 31, 2016, the fair value of Raging River's outstanding commodity contracts is an unrealized liability of $377 thousand 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, 2016, had the contracts been monetized or terminated. Subsequent changes in the fair value of the commodity contracts are recognized in the financial statements and could be materially different than what is recorded at December 31, 2016. The unrealized loss of $592 thousand represents the fair value change of the underlying commodity contracts to be settled in the future. In comparison, an unrealized loss of $2.3 million was recorded for the year ended December 31, 2015.

In the fourth quarter of 2016, the Company had unrealized gains of $374 thousand, compared to unrealized gains of $735 thousand in the fourth quarter of 2015.

Royalties

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	1,967	1,288	53	5,895	5,192	14
Saskatchewan resource surcharge	1,748	1,342	30	5,421	4,544	19
Freehold and GORR	5,581	3,782	48	17,291	15,157	14
	9,296	6,412	45	28,607	24,893	15
Percent of total revenue	9.4%	10.2%	(8)	9.6%	9.8%	(2)
Per boe ($)	4.94	4.72	5	4.37	4.97	(12)

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and Saskatchewan resource surcharge. Royalties increased to $9.3 million in the fourth quarter of 2016 from $6.4 million in the fourth quarter of 2015, primarily as a result of a 38% increase in production volumes. The Company's royalty rate decreased by 8% to 9.4% in the fourth quarter of 2016, from 10.2% in the comparable period of 2015, due to a larger percentage of wells drilled that qualified for Saskatchewan crown royalty incentives.

During the year ended December 31, 2016, royalties increased 15% to $28.6 million from $24.9 million in the comparable period. The increase is primarily a result of a 31% increase in production volumes. The royalty rate of 9.6% for the year ended December 31, 2016, was consistent with the royalty rate in the comparable period at 9.8%.

Operating Expenses

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
Total operating costs ($000's)	20,297	12,124	67	64,200	50,002	28
Percent of total revenue	20.6%	19.3%	7	21.6%	19.6%	10
Per boe ($)	10.79	8.92	21	9.80	9.99	(2)

During the three months ended December 31, 2016, operating expenses increased 67% to $20.3 million compared to $12.1 million in the same period of 2015. During the year ended December 31, 2016, operating expenses increased 28% to $64.2 million compared to $50 million in 2015. The increase in total operating costs is primarily due to the increase in production volumes in both the quarter and year ended December 31, 2016.

Operating costs averaged $10.79/boe in the fourth quarter of 2016 and $9.80/boe in the year to date. This represents an increase of 21% or $1.87/boe from $8.92/boe in the fourth quarter of 2015 and a decrease of 2% or $0.19/boe from $9.99/boe in the year ended December 31, 2015. The increase in per boe costs in the fourth quarter of 2016 is due to the heavy oil properties acquired as part of the Rock Acquisition, that carry higher operating costs than Raging River's historical average.

Transportation Expenses

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
Total transportation costs ($000's)	2,666	1,842	45	9,250	6,838	35
Percent of total revenue	2.7%	2.9%	(7)	3.1%	2.7%	15
Per boe ($)	1.42	1.36	4	1.41	1.37	3

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased to $2.7 million in the fourth quarter of 2016 from $1.8 million in the fourth quarter of 2015, due to the 38% increase in production volumes. During the year ended December 31, 2016, transportation costs increased 35% to $9.3 million from $6.8 million in the comparable period due to the 31% increase in production volumes.

Transportation costs averaged $1.42/boe in the fourth quarter of 2016 and $1.41/boe in the year to date. This represents an increase of 4% from $1.36/boe in the fourth quarter of 2015 and an increase of 3% from $1.37/boe in the year ended December 31, 2015. The nominal increase in per boe costs is attributable to higher clean oil trucking costs associated with the properties acquired through the Rock Acquisition.

General and Administrative ("G&A") Expenses

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	3,383	3,548	(5)	11,856	10,692	11
Overhead recoveries	(577)	(768)	(25)	(1,389)	(1,508)	(8)
Capitalized G&A	(934)	(940)	(1)	(2,985)	(2,673)	12
	1,872	1,840	2	7,482	6,511	15
Percent of total revenue	1.9%	2.9%	(34)	2.5%	2.6%	(4)
Per boe ($) – gross G&A	1.80	2.61	(31)	1.81	2.14	(15)
Per boe ($) – net G&A	1.00	1.35	(26)	1.14	1.30	(12)

The Company incurred gross G&A expenses of $3.4 million and $11.9 million, respectively, during the fourth quarter and year ended December 31, 2016. Increased general and administrative costs in 2016 before recoveries and capitalization were mainly the result of increased costs in consulting fees, increase in head office staff and software fees to accommodate the Company's increased capital expenditure program and the larger operations resulting from significant increases in production. Higher consulting fees were driven by increased personnel required to facilitate the integration of the Rock Acquisition. Higher salary costs were driven by increased personnel primarily technical and operations staff.

Net G&A expenses incurred were $1.9 million or $1.00 per boe and $7.5 million or $1.14 per boe, respectively, during the fourth quarter and year ended December 31, 2016. The decrease in net G&A per boe from the comparable periods is a result of continued G&A efficiencies achieved combined with higher production levels.

Financial Charges

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
Financial charges ($000's)	1,550	1,148	35	4,530	3,786	20
Percent of total revenue	1.6%	1.8%	(11)	1.5%	1.5%	-
Per boe ($)	0.82	0.84	(2)	0.69	0.76	(9)

Financial charges during the fourth quarter and year ended December 31, 2016, were $1.6 million and $4.5 million respectively, compared to $1.1 million and $3.8 million in the corresponding periods of 2015. The Company's financial charges increased in both the fourth quarter and year ended December 31, 2016 from the comparable periods of 2015, due to carrying higher average debt levels. Debt levels increased throughout 2016 to fund an increased capital expenditure program combined with the $58.3 million property acquisition that closed late in the fourth quarter, in addition to debt assumed from the Rock acquisition. As at December 31, 2016, the Company had drawn $168.2 million against the available credit facilities of $400 million.

In the fourth quarter of 2016, Raging River's borrowing base was reviewed and the syndicate of lenders underwriting the Company's credit facilities confirmed the increase in the Company's borrowing facility to $400 million from $300 million. The next borrowing base redetermination is scheduled for April 2017.

Stock-based Compensation

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Stock options	1,972	1,913	3	7,960	7,496	6
Share based awards	748	-	100	1,769	-	100
Capitalized stock based compensation	(661)	(492)	34	(2,330)	(2,026)	15
Stock based compensation expense	2,059	1,421	45	7,399	5,470	35
Percent of total revenue	2.1%	2.3%	(9)	2.5%	2.1%	19
Per boe ($)	1.09	1.05	4	1.13	1.09	4

Stock based compensation expense during the fourth quarter and year ended December 31, 2016, was $2.1 million and $7.4 million respectively, compared to $1.4 million and $5.5 million in the corresponding of 2015. Stock based compensation expense increased primarily due to the grant of additional stock options and the granting of share based awards.

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 have a three year vesting period 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, 2016, the Company had a total of 9.4 million (December 31, 2015 – 9.6 million) stock options outstanding with a weighted average fair value of $2.90 per stock option.

Share based awards

During the second quarter of 2016, the shareholders of the Company approved the Awards 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 plan shall not at any time exceed the lessor of: (i) 5% of the total common shares 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 Old Option Plan and New Option Plan. Currently one third of the RSUs will vest on each of the first, second and third anniversaries of the date of grant. PSUs will vest three years after the grant, unless otherwise determined by the board and are adjusted based on a payout multiplier. The payout multiplier ranges from 0 to 2 and is based on corporate performance measures determined by the board.

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, 2016, the Company had 222,550 RSUs and 276,050 PSUs outstanding.

On April 4, 2016, the board of directors of the Company approved the adoption of the Deferred Share Unit Plan ("DSU Plan"). Deferred Share Units ("DSUs") issued pursuant to the DSU Plan 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 1 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 price of the common shares on the date of grant.

As at December 31, 2016, the Company had 63,651 DSUs outstanding.

Depletion, Depreciation and Accretion

	Three months ended December 31,		Percent Change	Year ended December 31,		Percent Change
	2016	2015		2016	2015	
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	39,360	29,809	32	142,571	112,902	26
Exploration and evaluation lease expiries	160	-	100	3,152	2,512	25
Accretion	453	300	51	1,540	1,094	41
	39,973	30,109	33	147,263	116,508	26
Percent of total revenue	40.6%	47.8%	(15)	49.6%	45.7%	9
Per boe ($) – Depletion and depreciation	21.16	22.16	(5)	22.00	22.77	(3)
Per boe ($) – Exploration and evaluation lease expiries	0.08	-	100	0.48	0.50	(4)

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, 2016, were $39.3 million and $142.6 million respectively, compared to $29.8 million and $112.9 million for the corresponding periods in 2015. The increase in the depletion and depreciation expense in both the fourth quarter and year ended December 31, 2016, is due to the increase in production volumes combined with a significant increase to the capital base from capital expenditures and acquisitions.

Depletion per boe remained consistent in both the fourth quarter of 2016 and the year ended December 31, 2016 compared to 2015, as significant capital additions from drilling activities and acquisitions were offset by significant reserve additions. Total proved plus probable reserves grew to 94 million boe, a 23% increase over the December 31, 2015 reserves of 76.4 million boe. Future development costs of $813 million have been included in the capital base used in the calculation and salvage values of $49 million have been excluded in the calculation.

Accretion increased in the fourth quarter of 2016 to $453 thousand from $300 thousand in the comparable quarter of 2015. This increase is primarily due to the increase in asset retirement obligation from drilling and acquisition activities. Accretion represents the time value of the asset retirement obligation 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.

During the year ended December 31, 2016, $3.2 million of costs associated with expired mineral leases were recognized as an exploration and evaluation expense in the Statement of Comprehensive Earnings. In comparison, $2.5 million of lease expiries were recorded for the year ended December 31, 2015. Saskatchewan crown land leases come up for renewal annually in the first quarter of the year.

Asset Retirement Obligations

As at December 31, 2016, the asset retirement obligation of the Company was $97.8 million. The Company recorded an increase of $32.9 million in the obligation from the asset retirement obligation of $64.9 million as at December 31, 2015. This is related to the capital exploration and development program in 2016, the corporate and property acquisitions and an upward revision to the estimate. The revision to estimated asset retirement obligations of $3.4 million (December 31, 2015 - $8.7 million) in the year was due to a combination of discounting future cost estimates at a higher rate than in prior periods, which resulted in an decrease of $4.9 million, an increase in cost estimates of $0.8 million and the revaluation of asset retirement obligations acquired. Asset retirement obligations acquired as part of

an acquisition are initially measured at fair value using a credit-adjusted risk-free rate. The revaluation using a risk-free rate at the end of the period resulted in an increase of $7.5 million.

Income Taxes

The Company recorded a deferred income tax provision of $14.5 million and current tax recovery of $5.7 million for the year ended December 31, 2016. When combined, this resulted in an effective tax rate of 27%.

Raging River was not required to pay income taxes in the current and prior year as the Company had sufficient income tax deductions available to shelter taxable income. The Company's tax pools are estimated to be approximately $921.5 million as of December 31, 2016, up 43% from $646.1 million at December 31, 2015.

The federal tax pools are estimated as follows:

($ thousands)	Estimated balance at January 1, 2017
Canadian oil and gas property expense	242,827
Canadian development expense	386,996
Canadian exploration expense	14,695
Undepreciated capital cost	209,282
Non-capital losses	56,217
Share issue costs and other	11,435
Total	921,452

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, 2016, Raging River recorded funds flow from operations of $188.2 million, an increase of 12% from $167.4 in the comparable period of 2015. This increase from the 2015 funds flow from operations is primarily due to the increase in production volumes that was partially offset by a decline in commodity pricing.

The Company generated net earnings of $23.2 million in the year ended December 31, 2016, compared to net earnings of $28.9 million in the corresponding period of 2015. The Company achieved record production levels in 2016 which resulted in increased revenue however this was offset by higher cash expenses and a significant increase in depletion expense driven by increased production volumes, resulting in lower net earnings for 2016 compared to 2015. The net earnings for the year ended December 31, 2016, were positively impacted by the $4.3 million gain on acquisition due to the tax attributes relating to the Rock acquisition.

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, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
	($/boe)			*($/boe)*		
Petroleum and natural gas revenue	52.35	46.32	13	45.34	50.93	(11)
Realized gain (loss) on commodity contracts	(0.15)	0.89	(117)	-	0.91	(100)
Royalties	(4.94)	(4.72)	5	(4.37)	(4.97)	(12)
Net revenue	47.26	42.49	11	40.97	46.87	(13)
Operating expenses	(10.79)	(8.92)	21	(9.80)	(9.99)	(2)
Transportation expenses	(1.42)	(1.36)	4	(1.41)	(1.37)	3
Operating netback (1)	35.05	32.21	9	29.76	35.51	(16)
General and administrative expenses	(1.00)	(1.35)	(26)	(1.14)	(1.30)	(12)
Financial charges	(0.82)	(0.84)	(2)	(0.69)	(0.76)	(9)
Asset retirement expenditures	(0.12)	(0.06)	100	(0.07)	(0.02)	250
Current tax recovery	1.22	-	100	0.87	-	100
Funds flow from operations (1)	34.33	29.96	15	28.73	33.43	(14)
Unrealized gain (loss) on commodity contracts	0.20	(0.54)	(137)	(0.09)	(0.46)	(80)
Stock-based compensation expense	(1.09)	(1.05)	4	(1.13)	(1.09)	4
Gain on acquisition	2.30	-	100	0.66	-	100
Asset retirement expenditures	0.12	0.06	100	0.07	0.02	250
Exploration and evaluation lease expiries	(0.08)	-	100	(0.48)	(0.50)	(4)
Depletion, depreciation and accretion expense	(21.16)	(22.16)	(5)	(22.00)	(22.77)	(3)
Earnings before deferred income taxes	14.62	6.27	133	5.76	8.63	(33)
Deferred income taxes	(4.52)	(2.50)	81	(2.21)	(2.85)	(22)
Net earnings	10.10	3.77	168	3.55	5.78	(39)

(1) Non-GAAP measures. See Non-GAAP measures advisory.

Capital Expenditures

In the year ended December 31, 2016, the Company has invested a total of $403.2 million consisting of $211.6 million of exploration and development capital and $191.6 million of acquisition capital. The expenditures for the quarter and year ended December 31, 2016 are detailed below:

	Three months ended December 31, 2016	2015	Percent Change	Year ended December 31, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	1,325	1,715	(23)	4,424	2,946	50
Geological and geophysical	44	9	389	82	9	811
Drilling and completions	61,115	30,314	102	160,691	128,891	25
Facilities and equipping	14,160	11,661	21	46,261	39,173	18
Other	14	8	75	98	28	250
Exploration and development	76,658	43,707	75	211,556	171,047	24
Property acquisitions	58,259	(213)	N/A	83,384	39,731	110
Corporate acquisitions (1)(2)	-	128,413	(100)	108,308	128,413	(16)
Total invested capital	134,917	171,907	(22)	403,248	339,191	19

(1) The total cost of the Rock Acquisition includes $41.1 million of common share consideration based on a closing price of $10.56 per common share of Raging River and $67.2 million of net debt assumed.

(2) The total cost of the Anegada acquisition completed in 2015, included $95.6 million of common share consideration based on a closing price of $8.15 per common share of Raging River and $30.2 million of net debt assumed.

Exploration and development capital

In the year ended December 31, 2016, Raging River drilled a total of 311 (281.5 net) wells, primarily in the greater Dodsland area in southwest Saskatchewan, with a 99.6% success rate. This included 302 (272.5 net) crude oil wells, 8 (8.0 net) service wells and 1 (1.0 net) dry hole. By comparison, the Company drilled a total of 233 (216.9 net) wells in the year ended December 31, 2015 at a 99.7% success rate.

In the quarter ended December 31, 2016, the Company invested a total of $76.7 million on capital expenditures including $75.3 million on drilling, completing, and equipping activities and $1.4 million on land and geological and geophysical costs.

During the year ended December 31, 2016, the Company spent $211.6 million on capital expenditures including $207 million on drilling, completions and production facilities and $4.6 million on land, and geological and geophysical costs.

Corporate and property acquisitions

Dodsland Viking Acquisition

On November 28, 2016, the Company completed the Dodsland Viking property acquisition for cash consideration of $58.3 million prior to closing adjustments. The Company acquired approximately 620 boe/d (97% light oil) of production and 24 net sections of land prospective for Viking light oil. Acquired infrastructure included a natural gas processing facility and the associate pipelines network allowing the Company to tie-in approximately 1.5 mmcf/d of natural gas production.

Rock Acquisition

On July 21, 2016, the Company closed the Rock Acquisition for total consideration of approximately $108.3 million, comprised of 3.9 million common shares of Raging River at a closing price of $10.56 per common share and the assumption of $67.2 million of net debt.

The acquisition includes 2,550 boe/d (95% oil) of production and approximately 25 net sections of highly prospective land targeting Viking light oil in the Kerrobert area of southwest Saskatchewan complementary to Raging River's existing Viking assets. The Viking light oil drilling inventory associated with the acquisition includes over 200 net Viking horizontal unbooked drilling locations identified by Raging River. In addition to the Viking assets, Raging River also acquired interests in low decline, heavy oil assets, which include a recently initiated polymer flood at Mantario and legacy water floods at Onward, both in southwest Saskatchewan.

Forgan land consolidation

During the second quarter of 2016, the Company closed this property acquisition for cash consideration of $25.1 million. The property acquisition consisted of 30 net sections of crown land and 100 bbls/d of Viking light oil production.

2017 capital budget

The Company's board of directors has approved the 2017 exploration and development budget of $310 million. Raging River has allocated $260 million to drilling, completions and equipping, $40 million to waterflood and the remaining $10 million to land, seismic and maintenance capital. This budget will be funded from anticipated 2017 cash flow combined with the Company's existing credit facilities of $400 million.

Land Holdings

We have evaluated our undeveloped land holdings internally. This internal evaluation estimated the fair market value of our 428,100 net acres of undeveloped land holdings as at December 31, 2016, at $171.2 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 2016, Raging River significantly increased its undeveloped land base, targeting the Viking oil play in both southwest Saskatchewan and southeast Alberta. A total of 148,472 net acres of undeveloped land were acquired through land sales, property acquisitions and the Rock Acquisition. The following table summarizes our developed and undeveloped land holdings (in acres) as at December 31, 2016.

	Undeveloped		Developed		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Saskatchewan	366,338	322,960	90,907	81,143	457,245	404,103
Alberta	134,453	104,948	42,277	20,952	176,730	125,900
British Columbia	548	192	2,806	1,164	3,354	1,356
Total	501,339	428,100	135,990	103,259	637,329	531,359

(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,			
	2016		2015		2016		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	121	106.1	69	62.0	302	272.5	231	215.2
Natural gas	-	-	-	-	-	-	-	-
Test well	-	-	-	-	-	-	-	-
Service/Injection	6	6	1	1.0	8	8.0	1	1.0
Dry and abandoned	-	-	-	-	1	1.0	1	0.7
Total	127	112.1	70	63.0	311	281.5	233	216.9
Success	100%	100%	100%	100%	99.7%	99.6%	99.6%	99.7%

Liquidity and Capital Resources

At December 31, 2016, the Company had net debt of $209.5 million compared to net debt of $139.9 million at December 31, 2015. For the year ended December 31, 2016, funds flow from operations of $188.2 million combined with common share equity issuances for net proceeds of $102.4 million, stock option proceeds of $1.9 million less capital expenditures of $356.2 million and the assumption of $5.9 million working capital deficit on the Rock Acquisition, resulted in the ending net debt of $209.5 million.

The Company expects to have adequate liquidity to fund the updated 2017 capital expenditure budget of $310 million through a combination of funds flow from operations and the $400 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 $380 million extendible revolving credit facility with a syndicate of lenders and a $20 million extendible operating credit facility. The credit facilities have a revolving period currently expiring on April 27, 2017, 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 $500 million over all of the Company's assets and bear interest at rates that fluctuate, depending on the Company's debt to cash flow 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,	
	2016	2015
($ thousands)		
Capital Resources		
Bank debt available	400,000	300,000
Net debt	(209,543)	(139,943)
Total capital resources available	190,457	160,057

Changes to share capital in 2016 were the following:

On July 21, 2016, the Company completed the corporate acquisition of Rock through the issuance of 3.9 million common shares valued at the closing price of $10.56 per common share.

On March 9, 2016, the Company completed a bought deal financing for gross proceeds of $108.1 million and issued 12.5 million common shares at a price of $8.65 per common share.

During the year ended December 31, 2016, 1.8 million stock options were exercised for 795 thousand common shares on a cash-less basis and 529 thousand stock options were exercised for 529 thousand common shares for proceeds of $1.9 million.

Common share information

CAPITALIZATION

Share Capital

Outstanding common shares	Three months ended December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
Weighted average outstanding common shares [1]				
-Basic	231,114	202,977	225,946	197,701
-Diluted	232,048	203,897	226,533	198,601
Outstanding securities at December 31, 2016				
-Common shares				231,141,951
-Stock options – average strike price of $9.27				9,370,796
-Restricted share units				222,550
-Performance share units				276,050
-Deferred share units				63,651

(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, 2016 was approximately $2.4 billion.

	December 31, 2016
Common shares outstanding	231,141,951
Share price [1]	$10.56
Total market capitalization	$2,440,859,003

(1) Represents the last price traded on the TSX on December 30, 2016.

As at March 6, 2017 the Company had 231,144,656 common shares outstanding.

	March 6, 2017
Outstanding securities at March 6, 2017	
-Common shares	231,144,656
-Stock options – weighted average exercise price of $9.27	9,354,461
-Restricted share units	222,550
-Performance share units	276,050
-Deferred share units	94,571

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, 2016, the Company was committed to the future minimum payments as follows:

Payments due by period ($ thousands)	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years	Total
Office lease	901	1,501	-	-	2,402
Bank debt	-	168,194	-	-	168,194
Financial instruments	377	-	-	-	377
Processing	4,406	6,005	-	-	10,411
Transportation	2,738	6,403	-	-	9,141
Total contractual obligations and commitments	8,422	182,103	-	-	190,525

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, 2016.

Selected Annual Information

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

	2016	2015	2014
Financial ***(thousands of dollars except share data)***			
Average production volumes	17,900	13,715	10,755
Petroleum and natural gas revenue	297,020	254,932	336,838
Funds flow from operations [(1)]	188,188	167,351	221,650
Per share - basic	0.83	0.85	1.24
- diluted	0.83	0.84	1.19
Net earnings	23,212	28,919	110,170
Per share - basic	0.10	0.15	0.62
- diluted	0.10	0.15	0.59
Total assets	1,327,732	1,029,034	765,332
Net debt[(1)]	209,543	139,943	152,250
Weighted average shares *(thousands)*			
Basic	225,946	197,701	178,826
Diluted	226,533	198,601	186,602

(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

	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15
Financial ***(thousands of dollars except share data)***								
Petroleum and natural gas revenue	98,479	80,632	67,528	50,382	62,943	63,518	73,465	55,006
Funds flow from operations [(1)]	64,561	49,726	43,999	29,904	40,708	43,630	49,535	33,480
Per share - basic	0.28	0.22	0.19	0.14	0.20	0.22	0.25	0.18
- diluted	0.28	0.22	0.19	0.14	0.20	0.22	0.25	0.17
Net earnings	18,986	6,758	5,320	(7,852)	5,120	10,893	12,145	760
Per share - basic	0.08	0.03	0.02	(0.04)	0.03	0.05	0.06	0.00
- diluted	0.08	0.03	0.02	(0.04)	0.03	0.05	0.06	0.00
Capital expenditures, net	134,917	120,179	63,727	37,380	76,284	49,760	33,417	84,106
Shareholders' equity	899,120	877,442	826,775	817,839	719,213	616,834	602,539	587,903
Weighted average shares (thousands)								
Basic	231,114	230,227	226,231	216,493	202,977	199,576	197,882	190,207
Diluted	232,048	231,154	227,167	216,493	203,897	201,648	201,734	194,986

Shares outstanding, end of period *(thousands)*								
Basic	231,142	231,039	226,600	226,014	213,421	200,319	198,655	197,206
Diluted	241,011	240,570	236,768	235,896	223,051	211,265	211,320	209,692
Operating ***(6:1 boe conversion)***								
Average daily production								
Light oil and NGLs *(bbls/d)*	17,058	15,643	14,603	15,034	14,021	12,805	12,664	12,704
Heavy oil *(bbls/d)*	1,780	1,738	171	154	173	204	192	166
Natural gas *(mcf/d)*	9,652	7,385	7,368	7,900	3,461	2,454	2,947	2,641
Barrels of oil equivalent (2) *(boe/d)*	20,447	18,612	16,002	16,505	14,771	13,418	13,347	13,310
Average selling prices(4)								
Light oil and NGLs *($/bbl)*	56.56	50.78	49.68	35.47	47.64	52.54	60.20	46.93
Heavy oil *(bbls/d)*	43.51	37.66	31.10	17.84	31.72	39.38	51.92	36.70
Natural gas *($/mcf)*	2.91	2.06	1.10	1.89	2.31	2.82	2.59	2.73
Barrels of oil equivalent (2) *($/boe)*	52.35	47.09	46.37	33.54	46.32	51.45	60.49	45.92
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	52.35	47.09	46.37	33.54	46.32	51.45	60.49	45.92
Realized gain (loss) on commodity contracts	(0.15)	(0.05)	0.11	0.14	0.89	0.80	0.37	1.59
Royalties	(4.94)	(4.55)	(4.54)	(3.27)	(4.72)	(4.52)	(5.86)	(4.83)
Operating expenses	(10.79)	(10.15)	(8.98)	(8.95)	(8.92)	(9.14)	(10.69)	(11.36)
Transportation expenses	(1.42)	(1.46)	(1.39)	(1.37)	(1.36)	(1.37)	(1.39)	(1.35)
Operating netback *($/boe)*(5)	35.05	30.88	31.57	20.09	32.21	37.22	42.92	29.97
General and administrative	(1.00)	(1.15)	(1.20)	(1.26)	(1.35)	(1.18)	(1.30)	(1.37)
Financial charges	(0.82)	(0.63)	(0.46)	(0.82)	(0.84)	(0.71)	(0.83)	(0.63)
Asset retirement obligation	(0.12)	(0.05)	(0.04)	(0.03)	(0.06)	-	-	(0.02)
Current tax recovery	1.22	-	0.34	1.93	-	-	-	-
Funds flow netback(3) *($/boe)*	34.33	29.05	30.21	19.91	29.96	35.33	40.79	27.95

(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.

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 2016, 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 2015 and 2016 due to volatile commodity pricing. From the third quarter of 2016 to the fourth quarter of 2016, the increase in commodity pricing combined with increase in production levels in the fourth quarter of 2016, resulted in the increase of revenue, funds flow from operations and net earnings in the fourth quarter of 2016. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the fourth quarter of 2016.

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") 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, 2016 and have concluded that such disclosure controls and procedures are effective. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO Framework").

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 internal controls over financial reporting were effective as of December 31, 2016. There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2016 to December 31, 2016 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

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 decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third-party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 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, 2016 audited annual financial statements.

Future accounting pronouncements

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. Management is in the process of reviewing its revenue streams and assessing the potential impact, if any, of the adoption of IFRS 15 on the Company's financial statements.

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 profit or loss. 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. Management is currently assessing the potential impact of the adoption of IFRS 9 on the Company's financial statements.

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.

Corporate Information

Board of Directors

NEIL ROSZELL
President & CEO, 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

Officers

NEIL ROSZELL, P. Eng.
President & CEO

BRUCE BEYNON
Executive Vice President

JERRY SAPIEHA, CA
Vice President Finance & CFO

JASON JASKELA
Vice President Production & COO

JESSE BARLOW
Vice President Engineering

TERRY DANKU
Vice President of Business Development

CHAD LUNDBERG
Vice President Operations

SCOTT RIDEOUT
Vice President Land

TED BROWN (Corporate Secretary)
Burnet, Duckworth & Palmer LLP

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