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 August 11, 2016 and should be read in conjunction with the unaudited interim financial statements for the three and six months ended June 30, 2016 and the audited financial statements for the year ended December 31, 2015 and the notes thereto. The interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 – "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars, except when noted otherwise.

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 2016 capital budget including expected capital expenditures, the total number of wells to be drilled, total expected on-stream costs, expected sources of funding for the Company's 2016 capital budget, future drilling locations, expectations that the Company will not pay cash taxes in 2016, expectations that the Company will have adequate liquidity to fund operations and capital expenditures and expected sources of financing for any expansion of the capital program or any significant acquisition that may be undertaken by the Company. 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, changes in general economic conditions, whether farm-in and farm-out opportunities result in agreements and other factions more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities including the Company's most recent annual information form. 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 unaudited interim 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 June 30,		Six months ended, June 30,	
	2016	2015	2016	2015
	(thousands of dollars)		*(thousands of dollars)*	
Cash flow from operating activities	35,638	42,210	64,809	50,773
Changes in non – cash working capital	8,361	7,325	9,092	32,241
Funds flow from operations	43,999	49,535	73,901	83,014

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 firstly, the total amount of current and long-term debt the Company has, secondly, the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs and thirdly, 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. 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.

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 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.

Drilling Locations

This MD&A discloses certain drilling locations associated with the Company's acquisition of certain assets in the Forgan area of Saskatchewan. Such drilling locations are considered unbooked locations as they do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations may have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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 is presented on a gross basis, which is the Company's working interest prior to deduction of royalties and without including any royalty interests.

Corporate Highlights

SECOND QUARTER 2016 HIGHLIGHTS

- Achieved average quarterly production 16,002 boe/d (92% oil) representing an increase of 20% over the comparable period in 2015.

- The Company's exploration and development expenditures were $38.6 million including $36.5 million on drilling, completing and equipping activities and $2.1 million on land. A total of 39.9 net Viking horizontal wells were drilled at a 98% success rate.

- Completed the Forgan land consolidation for cash consideration of $25.1 million prior to closing adjustments. The property acquisition consisted of 30 net sections of crown land and 100 bbls/d of Viking light oil production. The Forgan lands included approximately 100 net high quality Viking drilling locations.

- On an unhedged basis, the Company generated industry leading operating netbacks of $31.46/boe and funds flow netbacks of $30.21/boe.

- Recorded net earnings of $5.2 million or $3.66 per boe primarily due to the increase in the Company's realized price and reduction of cash costs.

- Maintained balance sheet strength with second quarter exit net debt of $63.1 million representing 0.4 times net debt to the second quarter annualized cash flow.

SUBSEQUENT TO JUNE 30, 2016

- Following the end of the second quarter, the Company closed the previously announced corporate acquisition of Rock Energy Inc ("Rock"). Total consideration for the transaction is estimated to be $111 million comprised of the issuance of 3.896 million Raging River common shares and the assumption of approximately $70 million (unaudited) of net debt and assumed liabilities inclusive of bank debt, estimated working capital deficiency and Rock's expected transaction costs including severance obligations.

Petroleum and Natural Gas Operations

Production and Pricing

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
Operating: (6:1 boe conversion)						
Average daily production						
Liquids (bbls/d)	14,774	12,856	15	14,981	12,863	16
Natural gas (mcf/d)	7,368	2,947	150	7,634	2,795	173
Barrels of oil equivalent (boe/d)	16,002	13,347	20	16,253	13,329	22
Raging River average sales price						
Liquids ($/bbl)	49.68	62.20	(20)	42.48	54.60	(22)
Natural gas ($/mcf)	1.10	2.59	(58)	1.51	2.66	(43)
Barrel of oil equivalent ($/boe)	46.37	60.49	(23)	39.86	53.25	(25)
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	45.59	57.94	(21)	39.52	53.29	(26)
Crude Oil - MSW	54.70	67.64	(19)	47.70	59.71	(20)
Natural gas - AECO	1.42	2.67	(47)	1.62	2.71	(40)
Exchange rate (US$/Cdn$)	0.78	0.81	(4)	0.75	0.81	(7)

Revenues

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Liquids revenue	66,709	72,653	(8)	115,692	126,982	(9)
Natural gas revenue	740	696	6	2,097	1,345	56
Royalty revenue	79	116	(32)	120	144	(17)
	67,528	73,465	(8)	117,909	128,471	(8)

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 crude oil are determined by the quality of the crude compared to the benchmark price for Mixed Sweet Blend ("MSW"). The continued significant decline in the WTI price was only partially offset by the weak Canadian dollar in the second quarter and first half of 2016, which resulted in a lower realized price for the Company. The Company's liquids price averaged $49.68/bbl for the second quarter of 2016, down 20% from $62.20/bbl in the second quarter of 2015. Raging River's average quality adjustment to MSW pricing during the second quarter of 2016 decreased slightly to $5.02/bbl compared to $5.44/bbl in the second quarter of 2015. Raging River's quality adjustments are related to our average oil being 35º API versus the 40º API WTI benchmark, yielding an approximate $5/bbl differential to MSW.

Raging River's average quality adjustment to MSW pricing slightly increased in the first half of 2016 to $5.22/bbl from $5.11/bbl in the first half of 2015. The Company's liquids price averaged $42.48/bbl in the first half of 2016, down 22% from the average price of $54.60/bbl received in the first half of 2015.

The AECO natural gas price declined in the second quarter and first half of 2016, due to above average input into storage from an oversupplied market as warmer weather persists whereby reducing demand, resulting in a downward pressure on natural gas pricing and a decrease in the natural gas price realized by the Company. Raging River's realized natural gas price for the three and six month periods ended June 30, 2016 was $1.10 per mcf and $1.51 per mcf respectively, compared to $2.59 per mcf and $2.66 per mcf for the same periods in 2015. With depressed natural gas prices, early in the second quarter, the Company shut-in approximately 650 mcf/d of production.

Drilling

During the first half of 2016, the Company drilled a total of 98 gross (97.4 net) wells resulting in 96 (95.4 net) crude oil wells, 1 (1.0 net) service well and 1 (1.0 net) dry and abandoned well for a success rate of 99%.

Production	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14
Liquids (bbls/d)	14,774	15,188	14,194	13,009	12,856	12,870	12,059	10,278
Natural gas (mcf/d)	7,368	7,900	3,461	2,454	2,947	2,641	2,931	2,406
Total (boe/d)	16,002	16,505	14,771	13,418	13,347	13,310	12,548	10,679
% increase over prior quarter	(3%)	12%	10%	1%	-	6%	18%	7%
Production per 1 million shares	70.7	76.2	72.8	67.2	67.4	70.0	69.6	59.3
Per share % increase (decrease) over prior quarter	(7%)	5%	8%	-	(4%)	1%	17%	7%

The Company's production for the second quarter of 2016 increased to 16,002 boe/d from 13,347 boe/d in the second quarter of 2015, an increase of 20%. Quarter over quarter, production in the second quarter of 2016 of 16,002 boe/d decreased slightly against production of 16,505 boe/d in the first quarter of 2016. The year over year increase of 20% was primarily attributable to a successful drilling program in 2015 and 2016 combined with the strategic corporate acquisition that closed in December 2015.

Petroleum and natural gas revenue in the three month period June 30, 2016 was $67.5 million as compared to $73.5 million in the three month period June 30, 2015. This decrease was attributable to a 23% decrease in commodity pricing that was partially offset by a 20% increase in production volumes.

Petroleum and natural gas revenues in the six month period June 30, 2016 was $117.9 million, as compared to $128.5 million in the six month period June 30, 2015, representing a decrease of $10.6 million or 8%. This decrease in revenue is again attributed to a 25% decline in commodity prices that was partially offset by a 22% increase in production volumes.

Commodity Price Risk Management

Raging River, as part of our financial management strategy, has adopted a disciplined commodity hedging program. The objective of the hedging 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 hedging 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 August 11, 2016, the Company has the following price contracts in place by quarter:

2016

Q3					
Crude oil	Differential	Jul 2016 – Sept 2016	2,500 bbls/d	Cdn $4.37/bbl	WTI/Edm
Natural gas	Fixed	Jul 2016 – Sept 2016	3,640 GJs/d	Cdn $2.31/GJ	AECO
Q4					
Crude oil	Differential	Oct 2016 – Dec 2016	2,500 bbls/d	Cdn $4.89/bbl	WTI/Edm
Natural gas	Fixed	Oct 2016 – Dec 2016	2,500 GJs/d	Cdn $2.45/GJ	AECO

2017

Q1					
Crude oil	Differential	Jan 2017 – Mar 2017	1,000 bbls/d	Cdn $4.50/bbl	WTI/Edm
Natural gas	Fixed	Jan 2017 – Mar 2017	500 GJs/d	Cdn $3.00/GJ	AECO
Q2					
Crude oil	Differential	Apr 2017 – Jun 2017	1,000 bbls/d	Cdn $4.50/bbl	WTI/Edm
Q3					
Crude oil	Differential	Jul 2017 – Sep 2017	1,000 bbls/d	Cdn $4.95/bbl	WTI/Edm
Q4					
Crude oil	Differential	Oct 2017 – Dec 2017	1,000 bbls/d	Cdn $4.95/bbl	WTI/Edm

Realized & Unrealized Gain/Loss on Commodity Contracts

The realized gain/loss represents the commodity contracts settled during the three and six months ended June 30, 2016. As the oil commodity contracts are referenced to 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 significant decline in WTI in the first half of 2016 was only partially offset by the weak Canadian dollar which resulted in realized gains for the three and six months period ended June 30, 2016. For the three month period ended June 30, 2016, the Company realized gains of $154 thousand (three months ended June 30, 2015 - realized gains of $446 thousand) and for the six month period ended June 30, 2016, the Company recorded a $358 thousand gain (six months ended June 30, 2015 - realized gain of $2.3 million).

As of June 30, 2016, the fair value of Raging River's outstanding commodity contracts is an unrealized liability of $130 thousand as reflected in the interim financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been received as at June 30, 2016, had the contracts been monetized or terminated. Subsequent changes in the fair value of the commodity contracts are recognized in the interim financial statements and could be materially different than what is recorded at June 30, 2016. The unrealized loss of $345 thousand for the six month period ended June 30, 2016, represents the fair value change of the underlying commodity contracts to be settled in the future. In comparison, an unrealized loss of $2.6 million was recorded for the six months ended June 30, 2015.

In the second quarter of 2016, the Company had unrealized losses of $602 thousand compared to unrealized losses of $1.6 million in the second quarter of 2015.

Royalties

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	1,265	1,370	(8)	2,285	2,586	(12)
Saskatchewan resource surcharge	1,229	1,303	(6)	2,186	2,343	(7)
Freehold and GORR	4,112	4,443	(7)	7,044	7,977	(12)
	6,606	7,116	(7)	11,515	12,906	(11)
Percent of total revenue	9.8%	9.7%	1	9.8%	10.0%	(2)
Per boe ($)	4.54	5.86	(23)	3.89	5.35	(27)

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and the Saskatchewan resource surcharge. Royalties decreased to $6.6 million in the second quarter of 2016 from $7.1 million in the second quarter of 2015 primarily due to a 23% decline in commodity pricing. In the second quarter of 2016, the royalty rate of 9.8% was consistent with the royalty rate in the comparable period of 9.7%.

During the six months ended June 30, 2016, royalties decreased 11% to $11.5 million from $12.9 million in the comparable period. The decrease is again primarily a result of a 25% decrease in commodity pricing. The Company's average royalty rate was 9.8% in the first half of 2016 compared to 10.0% in the comparable quarter of 2015.

Operating Expenses

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
Total operating costs ($000's)	13,074	12,984	1	26,523	26,590	-
Percent of total revenue	19.4%	17.7%	10	22.5%	20.7%	9
Per boe ($)	8.98	10.69	(16)	8.97	11.02	(19)

Total operating expenses for the three and six months ended June 30, 2016 remained relatively unchanged from the same periods in 2015. During the three months ended June 30, 2016, operating expenses were $13.1 million compared to $13.0 million in the same period of 2015. During the six months ended June 30, 2016, operating expenses were $26.5 million compared to $26.6 million for the same period in 2015. Although production volumes increased in both the three and six months ended June 30, 2016, this was offset by mild spring break-up conditions and cost reduction initiatives.

Increased production in both the second quarter and six months of 2016 were offset by lower operating costs on a per boe basis. Operating costs averaged $8.98/boe in the second quarter of 2016 and $8.97/boe in the year to date. This represents a decrease of 16% or $1.71/boe from $10.69/boe in the second quarter of 2015 and a decrease of 19% or $2.05/boe from $11.02/boe in the first half of 2015. Operating costs per boe decreased in both the three and six month periods ended June 30, 2016, due to a combination of a component of operating costs being fixed with increased production, improved operating efficiencies and mild spring-break-up conditions.

Transportation Expenses

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
Total transportation costs ($000's)	2,025	1,688	20	4,082	3,305	24
Percent of total revenue	3.0%	2.3%	30	3.5%	2.6%	35
Per boe ($)	1.39	1.39	-	1.38	1.37	1

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased to $2.0 million in the second quarter of 2016 from $1.7 million in the second quarter of 2015. During the six month ended period June 30, 2016, transportation costs increased 24% to $4.1 million from $3.3 million in the comparable period. The increase in transportation costs is primarily due to the increase in production volumes in both the three and six month period ended June 30, 2016.

Transportation costs averaged $1.39/boe in the second quarter of 2016 and $1.38/boe in the year to date. Transportation costs per boe were consistent with the comparable period in both the three and six months period ended June 30, 2016.

General and Administrative ("G&A") Expenses

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	2,630	2,302	14	5,482	4,709	16
Overhead recoveries	(190)	(136)	40	(505)	(311)	62
Capitalized G&A	(692)	(589)	17	(1,339)	(1,181)	13
	1,748	1,577	11	3,638	3,217	13
Percent of total revenue	2.6%	2.1%	24	3.1%	2.5%	24
Per boe ($)	1.20	1.30	(8)	1.23	1.33	(8)

The Company incurred gross G&A expenses of $2.6 million and $5.5 million, respectively, during the three and six month periods ended June 30, 2016. Increased general and administrative costs before recoveries and capitalization were mainly the result of increased cost relating to head office staff and software fees to accommodate the Company's capital expenditure program and the larger operations resulting from significant increases in production. Higher salary costs were driven by increased personnel including technical and operations staff.

Net G&A expenses incurred were $1.7 million or $1.20 per boe and $3.6 million or $1.23 per boe, respectively, during the three and six month periods ended June 30, 2016. The decrease in net G&A per boe from the comparable periods is a result of efficiencies achieved with the higher production levels.

Financial Charges

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
Financial charges ($000's)	676	1,011	(33)	1,903	1,765	8
Percent of total revenue	1.0%	1.4%	(29)	1.6%	1.4%	14
Per boe ($)	0.46	0.83	(45)	0.64	0.73	(12)

Financial charges during the three and six month periods ended June 30, 2016, were $676 thousand and $1.9 million respectively compared to $1.0 million and $1.8 million respectively for 2015. Interest on bank debt decreased in the three month periods ended June 30, 2016, due to carrying lower average debt levels throughout the second quarter of 2016 as compared to 2015. In the first quarter of 2016, the Company completed a bought deal financing issuing 12.5 million common shares at $8.65 per common share for net proceeds of $102.8 million which allowed the Company to reduce debt and free up borrowing capacity. As at June 30, 2016 the Company had drawn $41.4 million against the available credit facility of $300 million.

Stock-based Compensation

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Stock based compensation costs	2,427	1,799	35	4,624	3,711	25
Capitalized stock based compensation	(506)	(489)	3	(1,049)	(1,019)	3
Stock based compensation expense	1,921	1,310	47	3,575	2,692	33
Percent of total revenue	2.8%	1.8%	56	3.0%	2.1%	43
Per boe ($)	1.32	1.08	22	1.21	1.12	8

Stock based compensation expense during the three and six month periods ended June 30, 2016, were $1.9 million and $3.6 million respectively compared to $1.3 million and $2.7 million respectively for 2015. Stock based compensation expense increased primarily due to the grant of additional options and the grants associated with the new Award Plan (as defined below).

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 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 June 30, 2016, the Company had a total of 9.7 million stock options outstanding with a weighted average fair value of $2.44 per option.

Award Plan

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 percent of the total common shares less the aggregate number reserved for issuance pursuant under the new stock option plan and (ii) 6.5 percent of the total common shares outstanding less the aggregate number of common shares reserved for issuance pursuant to the old stock options. 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 trading price 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 the exercise, 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 June 30, 2016, the Company had 150,150 RSUs and 248,450 PSUs outstanding.

Deferred Share Units ("DSUs")

On April 4, 2016, the board of directors of the Company approved the adoption of the DSU 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 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. The resulting stock-based compensation expense is recognized over the vesting period with the corresponding increase to contributed surplus. Upon the exercise, 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 June 30, 2016, the Company had 49,712 DSUs outstanding.

Depletion, Depreciation and Accretion

	Three months ended June 30,		Percent	Six months ended June 30,		Percent
	2016	2015	Change	2016	2015	Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	32,494	27,609	18	65,458	54,876	19
Exploration and evaluation lease expiries	502	-	100	2,699	2,512	7
Accretion	364	260	40	713	508	40
	33,360	27,869	20	68,870	57,896	19
Percent of total revenue	49.4%	37.9%	30	58.4%	45.1%	29
Per boe ($) – Depletion and depreciation	22.56	22.95	(2)	22.37	22.96	(3)
Per boe ($) – Exploration and evaluation lease expiries	0.34	-	100	0.91	1.04	(13)

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 increased to $32.5 million and $65.5 million respectively for the three and six month periods ended June 30, 2016. The increase in depletion expense is a result of an increase in production volumes, combined with a large increase to the capital base from capital expenditures from an intensive drilling program and the corporate acquisition that closed in December 2015. The per boe depletion and depreciation rate remained consistent for both the three and six month periods ended June 30, 2016, as capital additions were offset by reserve additions.

Accretion increased in the second quarter of 2016 to $364 thousand from $260 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%. It will continue to increase with the passage of time and the increases in asset retirement obligations.

During the six month period ended June 30, 2016, $2.7 million of costs associated with expired mineral leases were recognized as exploration and evaluation expense in the statement of comprehensive earnings. In comparison, $2.5 million of lease expiries were recorded in the first half of 2015. The majority of lease expiries are comprised of Saskatchewan crown land leases which come up for renewal annually in the first quarter of the year.

Asset Retirement Obligations

As at June 30, 2016, the asset retirement obligation of the Company was $75.0 million. The Company recorded an increase of $10.1 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 for the first half of 2016 and a revision to estimate. The Company recorded a revision to estimated asset retirement obligations of $3.3 million (December 31, 2015 - $8.7 million) in the year due to a combination of discounting future cost estimates at a lower rate than in prior periods which resulted in an increase of $3.0 million (December 31, 2015 - $1.7 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 $0.3 million (December 31, 2015 - $7.0 million).

Income Taxes

The Company recorded a deferred income tax provision of $2.9 million and a current tax recovery of $0.5 million for the three period ended June 30, 2016.

The Company recorded a deferred income tax provision of $3.8 million and current tax recovery of $3.4 million for the six month period ended June 30, 2016. When combined, this resulted in an effective tax rate of 26.4%. Based on the current forecast commodity prices, the Company does not expect to pay cash taxes in 2016.

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 six month period of operations ended June 30, 2016, Raging River recorded funds flow from operations of $73.9 million and net loss of $2.5 million. This decrease from the 2015 results with funds flow from operations of $83 million and net earnings of $12.9 million is due primarily to the significant decline in commodity pricing which was partially offset by increased production volumes and lower cash costs per boe.

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

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	($/boe)			($/boe)		
Petroleum and natural gas revenue	46.37	60.49	(23)	39.86	53.25	(25)
Realized gain on commodity contracts	0.11	0.37	(70)	0.12	0.97	(88)
Royalties	(4.54)	(5.86)	(23)	(3.89)	(5.35)	(27)
Net revenue	41.94	55.00	(24)	36.09	48.87	(26)
Operating expenses	(8.98)	(10.69)	(16)	(8.97)	(11.02)	(19)
Transportation expenses	(1.39)	(1.39)	-	(1.38)	(1.37)	1
Operating netback	31.57	42.92	(26)	25.74	36.48	(29)
General and administrative expenses	(1.20)	(1.30)	(8)	(1.23)	(1.33)	(8)
Financial charges	(0.46)	(0.83)	(45)	(0.64)	(0.73)	(12)
Asset retirement expenditures	(0.04)	-	(100)	(0.04)	(0.01)	(300)
Current tax recovery	0.34	-	100	1.15	-	100
Funds flow from operations	30.21	40.79	(26)	24.98	34.41	(27)
Unrealized loss on financial instruments	(0.41)	(1.33)	(69)	(0.12)	(1.10)	(89)
Stock-based compensation expense	(1.32)	(1.08)	(22)	(1.21)	(1.12)	8
Asset retirement expenditures	0.04	-	100	0.04	0.01	300
Exploration and evaluation lease expiries	(0.34)	-	(100)	(0.91)	(1.04)	(13)
Depletion, depreciation and accretion expense	(22.56)	(22.95)	(2)	(22.37)	(22.96)	(3)
Earnings before taxes	5.62	15.43	(64)	0.41	8.20	(95)
Deferred income tax provision	(1.96)	(5.43)	(64)	(1.27)	(2.86)	(56)
Net earnings (loss)	3.66	10.00	(63)	(0.86)	5.34	(116)

Capital Expenditures

Total exploration and development capital expenditures for the three and six month periods ended June 30, 2016, were $63.7 million and $101.1 million respectively, compared to $33.4 million and $117.5 million for the same periods in 2015. The expenditures are detailed below:

	Three months ended June 30, 2016	2015	Percent Change	Six months ended June 30, 2016	2015	Percent Change
	(thousands of dollars)			(thousands of dollars)		
Land	2,041	1,094	87	2,578	1,411	83
Property acquisitions	25,125	-	100	25,125	35,729	(30)
Geological and geophysical	23	10	130	26	11	136
Drilling and completions	28,420	30,772	(8)	55,976	77,770	(28)
Equipping and facilities	8,098	1,538	427	17,346	2,583	572
Other	20	3	567	56	19	195
Exploration and development	63,727	33,417	91	101,107	117,523	(14)

In the first half of 2016, Raging River drilled a total of 98 (97.4 net) wells. This included 96 (95.4 net) crude oil wells, 1 (1.0 net) service well and 1 (1.0) dry and abandoned well for an overall success rate of 99%. In the second quarter of 2016, Raging River drilled a total of 40 (39.9 net) crude oil wells with a success rate of 98%. By comparison, the Company drilled a total of 36 (36.0 net) wells in the second quarter of 2015 and 96 (89.3 net) wells in the six month period ended June 30, 2015.

In the three months ended June 30, 2016, the Company invested a total of $63.7 million on capital expenditures including $36.5 million on drilling, completing, and equipping activities, $2.1 million on land and geological and geophysical costs and $25.1 million on a property acquisition. The property acquisition consisted of 30 net sections of crown land and 100 bbls/d of Viking light oil production.

During the first half of 2016, the Company spent $101.1 million on capital expenditures including $73.3 million on drilling, completions and production facilities, $2.7 million on land and geological and geophysical costs and $25.1 million on a property acquisition.

On July 20, 2016, the board of directors approved an increase in the capital expenditure budget to $220 million excluding the acquisition of Rock. Raging River's amended 2016 budget includes the drilling of approximately 230 net Viking oil wells. Total on-stream costs (drilling, completion and equipping) are expected to represent $174 million or 79% of the approved 2016 budget of $220 million. The Company has allocated $15 million for waterflood, $25 million for the property acquisition discussed above with the remaining $6 million to land, seismic and maintenance capital. The capital budget will be funded from a combination of anticipated 2016 cashflow and the Company’s credit facility of $300 million.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended June 30,				Six months ended June 30,			
	2016		2015		2016		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	39	38.9	36	36.0	96	95.4	96	89.3
Natural gas	-	-	-	-	-	-	-	-
Test well	-	-	-	-	-	-	-	-
Service	-	-	-	-	1	1.0	-	-
Dry and abandoned	1	1.0	-	-	1	1.0	-	-
Total	40	39.9	36	36.0	98	97.4	96	89.3
Success (1)	98%	98%	100%	100%	99%	99%	100%	100%

(1) Does not include service well.

Liquidity and Capital Resources

At June 30, 2016, the Company had net debt of $63.1 million compared to net debt of $139.9 million at December 31, 2015. For the six months ended June 30, 2016, funds flow from operations of $73.9 million combined with common share equity issuances for net proceeds of $102.8 million, stock option proceeds of $1.2 million less capital expenditures of $101.1 million resulted in the ending net debt of $63.1 million. The Company expects to have adequate liquidity to fund the 2016 capital expenditure budget of $220 million through a combination of funds flow from operations and the $300 million syndicated credit facility. 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.

Capital Resources

	June 30, 2016	2015
($ thousands)		
Capital Resources		
Bank debt available	300,000	300,000
Net debt	(63,101)	(99,058)
Total capital resources available	236,899	200,942

Changes to share capital in 2016 were the following:

During the six months ended June 30, 2016, 674 thousand stock options were exercised for 339 thousand common shares on a cash-less basis and 341 thousand stock options were exercised for 341 thousand common shares for gross proceeds of $1.2 million.

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.

Common share information

CAPITALIZATION

Share Capital

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Weighted average outstanding common shares (1)				
-Basic	226,231	197,882	221,362	194,067
-Diluted	227,167	201,734	221,362	197,754
Outstanding securities at June 30, 2016				
-Common shares				226,600,476
-Common share options – average strike price of $8.77				9,719,679
-Restricted share units				150,150
-Performance share units				248,450
-Deferred share units				49,712

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, PSUs and DSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted profit per common share. In computing the diluted loss per common share for the six months ended June 30, 2016, the Company excluded the effect of stock options, RSUs, PSUs and DSUs as they were anti-dilutive. Therefore, the diluted weighted average is equal to the basic weighted average shares outstanding.

Total Market Capitalization

The Company's market capitalization at June 30, 2016 was approximately $2.3 billion.

	June 30, 2016
Common shares outstanding	226,600,476
Share price (1)	$10.28
Total market capitalization	$2,329,452,893

(1) Represents the closing price traded on the TSX on June 30, 2016.

As at August 11, 2016 the Company had 230,512,474 common shares outstanding.

	August 11, 2016
Outstanding securities at August 11, 2016	
-Common shares	230,512,474
-Stock options – weighted average exercise price of $8.83	10,068,678
-Restricted share units	150,150
-Performance share units	248,450
-Deferred share units	49,712

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 that follows:

Contractual Obligations

Payments due by Period ($ thousands)	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years	Total
Office lease	904	1,958	-	-	2,862
Bank debt	-	41,436	-	-	41,436
Financial instruments	130	-	-	-	130
Total contractual obligations	1,034	43,394	-	-	44,428

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 first half of 2016.

Subsequent Event

On July 21, 2016, the Company closed the acquisition, by way of plan of arrangement, of all issued and outstanding of Rock Energy Inc. ("Rock"), a public oil and gas company with properties in Alberta and Saskatchewan. Total consideration for the transaction is estimated to be $111 million comprised of the issuance of 3.896 million Raging River shares at a price of $10.56 per share and the assumption of approximately $70 million (unaudited) of net debt and assumed liabilities inclusive of bank debt, estimated working capital deficiency and Rock's expected transaction costs including severance obligations. This acquisition includes 2,550 boe/d (95% oil) of production and approximately 25 net sections of land targeting Viking light oil in the Kerrobert area of southwest Saskatchewan.

Summary of Quarterly Results

	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	67,528	50,382	62,943	63,518	73,465	55,066	78,634	88,566
Funds flow from operations (1)	43,999	29,904	40,708	43,630	49,535	33,480	57,704	57,850
Per share - basic	0.19	0.14	0.20	0.22	0.25	0.18	0.32	0.32
- diluted	0.19	0.14	0.20	0.22	0.25	0.17	0.31	0.31
Net earnings	5,320	(7,852)	5,120	10,893	12,145	760	24,067	31,505
Per share - basic	0.02	(0.04)	0.03	0.05	0.06	0.00	0.14	0.17
- diluted	0.02	(0.04)	0.03	0.05	0.06	0.00	0.13	0.17
Capital expenditures, net	63,727	37,380	76,284	49,760	33,417	84,106	97,123	81,664
Shareholders' equity	826,775	817,839	719,213	616,834	602,539	587,903	496,984	470,775
Weighted average shares								
Basic	226,231	216,493	202,977	199,576	197,882	190,207	180,256	180,081
Diluted	227,167	216,493	203,897	201,648	201,734	194,986	187,394	188,442
Shares outstanding, end of period *(thousands)*								
Basic	226,600	226,014	213,421	200,319	198,655	197,206	180,332	180,209
Diluted	236,768	235,896	223,051	211,265	211,320	209,692	196,064	195,755
Operating *(6:1 boe conversion)*								
Average daily production								
Crude oil and NGLs *(bbls/d)*	14,774	15,188	14,194	13,009	12,856	12,870	12,059	10,278
Natural gas *(mcf/d)*	7,368	7,900	3,461	2,454	2,947	2,641	2,931	2,406
Barrels of oil equivalent (2) *(boe/d)*	16,002	16,505	14,771	13,418	13,347	13,310	12,548	10,679
Average selling prices(4)								
Crude oil and NGLs *($/bbl)*	49.68	35.47	47.64	52.54	62.20	46.93	70.00	92.79
Natural gas *($/mcf)*	1.10	1.89	2.31	2.82	2.59	2.73	3.60	3.74
Barrels of oil equivalent (2) *($/boe)*	46.37	33.54	46.32	51.45	60.49	45.92	68.12	90.14
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	46.37	33.54	46.32	51.45	60.49	45.92	68.12	90.14
Realized gain (loss) on commodity contracts	0.11	0.14	0.89	0.80	0.37	1.59	4.01	0.13
Royalties	(4.54)	(3.27)	(4.72)	(4.52)	(5.86)	(4.83)	(5.33)	(8.89)
Operating expenses	(8.98)	(8.95)	(8.92)	(9.14)	(10.69)	(11.36)	(11.45)	(11.75)
Transportation expenses	(1.39)	(1.37)	(1.36)	(1.37)	(1.39)	(1.35)	(1.30)	(1.95)
Operating netback *($/boe)*	31.57	20.09	32.21	37.22	42.92	29.97	54.05	67.68
General and administrative	(1.20)	(1.26)	(1.35)	(1.18)	(1.30)	(1.37)	(1.44)	(1.39)
Financial charges	(0.46)	(0.82)	(0.84)	(0.71)	(0.83)	(0.63)	(0.71)	(0.91)
Asset retirement obligation	(0.04)	(0.03)	(0.06)	-	-	(0.02)	(0.09)	-
Current taxes	0.34	1.93	-	-	-	-	(1.82)	(6.51)
Funds flow netback(3) *($/boe)*	30.21	19.91	29.96	35.33	40.79	27.95	49.99	58.87

(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, transaction costs and current taxes.
(4) Excludes unrealized risk management 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 2016 production, revenues, funds flow from operations and net earnings. The decrease in revenue, funds flow from operations and net earnings in the first half of 2016 is primarily due to lower commodity prices. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the second 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.

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 Internal Control - Integrated Framework (2013) ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). There have been no changes in the Company's internal controls over financial reporting during the period from April 1, 2016 to June 30, 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 status 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 values of stock options and warrants using pricing models such as the Black-Scholes model is based on significant assumptions such as volatility, forfeiture rates and the expected term.

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, 2015 audited annual financial statements, except as noted below. Those accounting policies have been applied consistently to all periods presented in the Company's interim financial statements.

Future accounting pronouncements

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 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 new standard is effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. The IASB has proposed to defer the adoption date to January 2018. Management is currently assessing the potential impact of the adoption of IFRS 15 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 Business Development

SCOTT RIDEOUT
Vice President Land

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

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