

MANAGEMENT'S DISCUSSION & ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of the financial and operating results of Petrus Resources Ltd. ("Petrus" or "the Company") as at and for the three and six months ended June 30, 2018. The MD&A is dated August 8, 2018 and should be read in conjunction with the Company's June 30, 2018 interim consolidated financial statements and the December 31, 2017 audited annual consolidated financial statements. The Company's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are directed to the advisories at the end of this report regarding forward-looking statements and boe presentation and to the section "Non-GAAP Financial Measures" herein.

The principal undertaking of Petrus is the investment in energy assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. The Company's head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada. Additional information on Petrus, including the most recently filed Annual Information Form ("AIF"), are available under the Company's profile on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

SELECTED FINANCIAL INFORMATION

OPERATIONS	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Average Production					
Natural gas (mcf/d)	39,126	42,392	45,543	46,625	45,550
Oil (bbl/d)	1,484	2,015	1,530	1,854	1,877
NGLs (bbl/d)	1,241	1,160	1,475	1,086	1,098
Total (boe/d)	9,246	10,240	10,596	10,711	10,567
Total (boe)	841,316	931,821	953,598	985,388	972,140
Natural gas sales weighting	71%	69%	72%	73%	72%
Realized Prices					
Natural gas (\$/mcf)	1.24	3.29	2.18	1.90	1.66
Oil (\$/bbl)	75.29	59.02	73.91	66.10	51.23
NGLs (\$/bbl)	41.53	30.32	46.50	38.00	24.79
Total realized price (\$/boe)	22.92	28.69	26.50	23.56	18.82
Royalty income	0.05	0.03	0.03	0.03	0.01
Royalty expense	(2.54)	(4.62)	(4.90)	(3.04)	(2.73)
Net oil and natural gas revenue (\$/boe)	20.43	24.10	21.63	20.55	16.10
Operating expense	(4.57)	(5.53)	(4.36)	(4.81)	(5.42)
Transportation expense	(1.17)	(1.32)	(1.26)	(1.25)	(1.29)
Operating netback ⁽¹⁾ (\$/boe)	14.69	17.25	16.01	14.49	9.39
Realized gain (loss) on derivatives	(0.74)	0.23	0.31	1.23	1.88
Other income	0.12	—	—	—	—
General & administrative expense	(1.63)	(1.12)	(1.50)	(0.27)	(1.09)
Cash finance expense	(2.49)	(1.94)	(1.96)	(1.54)	(1.99)
Decommissioning expenditures	—	(1.03)	(0.23)	(0.62)	(0.23)
Corporate netback ⁽¹⁾ (\$/boe)	9.95	13.39	12.63	13.29	7.96

FINANCIAL (\$000s except per share)	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Oil and natural gas revenue	19,321	26,753	25,301	23,243	18,299
Net loss	(10,615)	(781)	(5,684)	(67,095)	(50,696)
Net loss per share					
Basic	(0.21)	(0.02)	(0.11)	(1.36)	(1.03)
Fully diluted	(0.21)	(0.02)	(0.11)	(1.36)	(1.03)
Funds flow	8,364	12,458	12,105	13,084	7,727
Funds flow per share					
Basic	0.17	0.25	0.24	0.26	0.16
Fully diluted	0.17	0.25	0.24	0.26	0.16
Capital expenditures	1,745	18,903	6,056	21,885	13,055
Net acquisitions (dispositions)	(269)	—	(123)	789	(4,866)
Weighted average shares outstanding					
Basic	49,492	49,428	49,492	49,456	49,428
Fully diluted	49,492	49,428	49,492	49,456	49,428
As at period end					
Common shares outstanding (000s)					
Basic	49,492	49,428	49,492	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,492	49,428
Total assets	330,359	465,794	343,161	353,445	409,078
Non-current liabilities	172,757	170,580	174,634	173,272	191,145
Net debt ⁽¹⁾	135,111	137,069	142,238	148,066	137,531

⁽¹⁾ Refer to "Non-GAAP Financial Measures".

OPERATIONS UPDATE

Production

Average second quarter production by area was as follows:

For the three months ended June 30, 2018	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	28,734	3,225	7,167	39,126
Oil (bbl/d)	845	203	435	1,483
NGLs (bbl/d)	1,039	15	188	1,241
Total (boe/d)	6,672	756	1,818	9,246
Natural gas sales weighting	72%	71%	66%	71%

Second quarter average production was 9,246 boe/d (71% natural gas) in 2018 compared to 10,240 boe/d (69% natural gas) in the second quarter of 2017. The 10% decrease is attributable to certain production volume in the Foothills area being shut-in due to uneconomic natural gas pricing.

Capital Development ⁽¹⁾

The Company achieved year over year annual average production growth of 24% from 2016 to 2017 as a result of Petrus' strategic focus on its Ferrier production growth. However, in response to the current commodity price outlook for natural gas, the Company shifted its 2018 focus to prioritize light oil drilling opportunities and to direct excess funds flow towards debt repayment. To date in 2018, Petrus has drilled or participated in 2 (0.7 net) Cardium light oil wells in Ferrier and has reduced net debt by \$13.0 million or 9%. The Company's 2018 capital program is scheduled to recommence in August and Petrus expects to drill an additional 7 (3.7 net) Cardium light oil wells during the second half of 2018.

⁽¹⁾ Refer to "Advisories - Forward-Looking Statements".

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Three months ended Jun. 30, 2018	Three months ended Jun. 30, 2017	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017	Three months ended Sept. 30, 2017
Average production					
Natural gas (mcf/d)	39,126	42,392	45,543	46,625	45,550
Oil (bbl/d)	1,484	2,015	1,530	1,854	1,877
NGLs (bbl/d)	1,241	1,160	1,475	1,086	1,098
Total (boe/d)	9,246	10,240	10,596	10,711	10,567
Total (boe)	841,316	931,821	953,598	985,388	972,140
Revenue (\$000s)					
Natural Gas	4,432	12,708	8,918	8,149	6,939
Oil	10,159	10,822	10,175	11,273	8,848
NGLs	4,692	3,199	6,175	3,796	2,504
Royalty revenue	38	24	33	25	8
Oil and natural gas revenue	19,321	26,753	25,301	23,243	18,299
Average realized prices					
Natural gas (\$/mcf)	1.24	3.29	2.18	1.90	1.66
Oil (\$/bbl)	75.29	59.02	73.91	66.10	51.23
NGLs (\$/bbl)	41.53	30.32	46.50	38.00	24.79
Total realized price (\$/boe)	22.92	28.69	26.50	23.56	18.82
Hedging gain (loss) (\$/boe)	(0.74)	0.23	0.31	1.23	1.88
Total price including hedging (\$/boe)	22.18	28.92	26.81	24.79	20.70
Average benchmark prices					
Natural gas					
AECO 5A (\$/GJ)	1.12	2.57	1.97	1.60	1.38
AECO 7A (\$/GJ)	0.97	2.63	1.76	1.86	1.93
Crude Oil					
Edm Lt. (\$/bbl)	78.91	60.36	72.28	66.93	57.08
Foreign Exchange					
US\$/C\$	0.78	0.74	0.80	0.78	0.80

FUNDS FLOW AND NET INCOME (LOSS)

Petrus generated funds flow of \$8.4 million in the second quarter of 2018, a 33% decrease relative to the \$12.5 million generated in the second quarter of 2017. The decrease is due to 10% lower production and 63% lower natural gas pricing (AECO 7A monthly index) partially offset by commodity hedging contracts in place. On a six month basis, funds flow was \$20.5 million compared to \$24.2 million in the prior year. The 15% decrease is due to 51% lower natural gas pricing (AECO 7A monthly index), offset by 10% lower operating expenses and 21% higher light oil pricing (Edm CAD\$).

Petrus reported a net loss of \$10.6 million in the second quarter of 2018, compared to a net loss of \$0.8 million in the second quarter of the prior year. The higher net loss is due to accounting for the unrealized, non-cash, mark to market of the Company's risk management contracts. In the second quarter of 2018, Petrus recorded an \$8.3 million unrealized hedging loss on financial derivatives whereas in the second quarter of 2017 a \$0.4 million unrealized hedging gain on financial derivatives was recorded. On a six month basis, the Company generated net income of \$6.5 million for the six months ended June 30, 2017 compared to a net loss of \$16.3 million for the six months ended June 30, 2018. The accounting for the unrealized hedging on financial derivatives had a material impact on the earnings; in 2017 the Company recognized an unrealized gain of \$8.4 million whereas in 2018 a \$13.9 unrealized loss was recorded. The differences are due to changes in commodity prices at June 30 of the respective years.

(\$000s except per share)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Funds flow	8,364	12,458	20,469	24,190
Funds flow per share - basic	0.17	0.25	0.41	0.49
Funds flow per share - fully diluted	0.17	0.25	0.41	0.49
Net income (loss)	(10,615)	(781)	(16,299)	6,530
Net income (loss) per share - basic	(0.21)	(0.02)	(0.33)	0.14
Net income (loss) per share - fully diluted	(0.21)	(0.02)	(0.33)	0.14
Common shares outstanding (000s)				
Basic	49,492	49,428	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,429
Weighted average shares outstanding (000s)				
Basic	49,492	49,428	49,492	48,098
Fully diluted	49,492	49,428	49,492	48,140

OIL AND NATURAL GAS REVENUE

Average production for the second quarter of 2018 was 9,246 boe/d (71% natural gas), 10% lower than the 10,240 boe/d (69% natural gas) average production for the second quarter of the prior year. The decrease is attributable to uneconomic dry gas production currently shut-in in the Company's Foothills area as a result of the low natural gas price environment. Total oil and natural gas revenue for the second quarter of 2018 decreased from \$26.8 million in 2017 to \$19.3 million in 2018. The 28% decrease is due to lower production and lower natural gas pricing.

Average production for the first six months of 2018 was 9,918 boe per day (71% natural gas), compared to 9,788 boe per day (70% natural gas) for the prior year comparative period. Total oil and natural gas revenue decreased from \$49.0 million in the first six months of 2017 to \$44.6 million in the six months ended June 30, 2018 mainly due to lower natural gas pricing.

Natural gas

During the three and six months ended June 30, 2018, the average benchmark natural gas price in Canada (AECO 7A monthly index) decreased by 63% and 50%, respectively, from the prior year comparative periods (average price of \$1.03 per mcf in the second quarter of 2018 compared to \$2.77 per mcf in the second quarter of the prior year, and \$1.44 per mcf for the first six months of 2018, compared to \$2.86 per mcf for the prior year comparative period).

The Company's average realized natural gas price during the second quarter of 2018 was \$1.24 per mcf, compared to \$3.29 per mcf in the second quarter of 2017, which represents a 62% decrease. Natural gas revenue for the second quarter of 2018 was \$4.4 million and production of 3,560,488 mcf accounting for approximately 71% of second quarter production volume and 23% of oil and natural gas revenue, compared to revenue of \$12.7 million and production of 3,857,621 mcf accounting for approximately 69% of second quarter production volume and 48% of oil and natural gas revenue in the prior year comparative period. Natural gas revenue decreased from the prior year due to lower natural gas prices during the second quarter of 2018.

Natural gas revenue for the first six months of 2018 was \$13.4 million and production of 7,659,369 mcf accounted for approximately 71% of production volume in the period and 30% of oil and natural gas revenue, compared to revenue of \$23.1 million and production of 7,487,531 mcf for 70% of production volume and 39% of oil and natural gas revenue in the prior year comparative period. The decrease is due to decreased natural gas prices.



Crude oil and condensate

Edmonton Light Sweet crude oil prices increased 31% from the second quarter of 2017 to the second quarter of 2018 (an average price of \$78.91 per bbl for the second quarter of 2018 compared to an average price of \$60.36 per bbl for the prior year comparative period). Prices increased 21% from the first six months of 2017 to the first six months of 2018 (\$75.60 per bbl in 2018 compared to an average of \$62.56 per bbl in the prior year comparative period).

Similarly, the average realized price of Petrus' crude oil and condensate was \$75.29 per bbl for the second quarter of 2018 compared to \$59.02 per bbl for the same period in the prior year. Petrus' realized oil price was lower than the corresponding marker due to lower oil quality.

Oil and condensate revenue for the second quarter of 2018 was \$10.2 million and production of 134,933 bbl accounted for approximately 16% of total production volume and 53% of oil and natural gas revenue, compared to revenue of \$10.8 million and production of 183,352 bbl accounted for approximately 20% of total production volume and 40% of oil and natural gas revenue in the second quarter of the prior year.

Oil and condensate revenue for the first six months of 2018 was \$20.3 million and production of 272,598 bbl accounted for approximately 15% of total production volume and 46% of oil and natural gas revenue, compared to revenue of \$19.5 million and production of 322,121 for 18% of total production volume and 40% of oil and natural gas revenue in the first six months of the prior year.

Natural gas liquids (NGLs)

The Company's NGL production mix consists of ethane, propane, butane, pentane and sulphur. The pricing received for NGL production is based on the product mix, the fractionation process required and the demand for fractionation facilities. In the second quarter of 2018, the overall realized NGL price averaged \$41.53 per bbl, compared to \$30.32 per bbl in the prior year. The increase is attributed to improved commodity prices as well as a change in the composition of the Company's NGLs.

NGL revenue for the second quarter of 2018 was \$4.7 million and production of 112,968 bbl accounted for approximately 13% of production volume and 24% of oil and natural gas revenue, compared to revenue of \$3.2 million and production of 105,533 bbl accounted for approximately 11% of production volume and 12% of oil and natural gas revenue for the second quarter of the prior year.

NGL revenue for the first six months of 2018 was \$10.9 million and production of 272,598 bbl accounted for approximately 15% of production volume and 24% of oil and natural gas revenue in the period, compared to revenue of \$6.4 million and production of 201,524 bbl for 11% of production volume and 13% of oil and natural gas revenue in the first six months of the prior year.

ROYALTY EXPENSES

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company's royalty expenses for the periods shown:

Royalty Expenses (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Crown	334	2,042	2,509	3,496
Percent of production revenue	2%	16%	6%	7%
Gross overriding	1,803	2,264	4,302	4,119
Total	2,137	4,306	6,811	7,615

Total royalty expense (net of royalty allowances and incentives) decreased from \$4.3 million in the second quarter of 2017 to \$2.1 million in the second quarter of 2018 primarily due to the change in the annual gas cost allowance ("GCA") adjustment. Each year during the second quarter, the Company receives information related to its GCA credits, which results in an annual adjustment recorded to adjust GCA received through the prior year. In addition, second quarter royalty expense in 2018 was lower than 2017 as a result of lower natural gas prices.

On a six month basis, total royalty expense (net of royalty allowances and incentives) decreased from \$7.6 million in 2017 to \$6.8 million in 2018. The decrease is due to lower natural gas prices.

Gross overriding royalties decreased from \$2.3 million in the second quarter of 2017 to \$1.8 million in the second quarter of 2018, due to lower natural gas prices. Gross overriding royalties increased from \$4.1 million for the six months ended June 30, 2017 to \$4.3 million for the six months ended June 30, 2018, due to additional wells being drilled on land with gross overriding royalty burdens.

RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility, increase the certainty of cash flows from operating activities and protect acquisition and development economics. Petrus' risk management program is governed by guidelines approved by its Board of Directors.



The impact of the contracts that were outstanding during the reporting periods are actual cash settlements and are recorded as realized hedging gains (losses). The unrealized gain (loss) is recorded to demonstrate the change in fair value of the outstanding contracts during the financial reporting period for financial statement purposes. Petrus does not follow hedge accounting for any of its risk management contracts in place. Petrus considers all of its risk management contracts to be effective economic hedges of its underlying business transactions.

The table below shows the realized and unrealized gain or loss on risk management contracts for the periods shown:

Net Gain (Loss) on Financial Derivatives (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Realized hedging gain (loss)	(625)	212	(327)	694
Unrealized hedging gain (loss)	(8,323)	376	(13,863)	8,424
Net gain (loss) on derivatives	(8,948)	588	(14,190)	9,118

The Company recognized a realized hedging loss of \$0.6 million during the second quarter of 2018, compared to a \$0.2 million gain realized in the same quarter of the prior year. The realized loss in the current period is due to higher crude oil prices offset by lower natural gas prices. The realized loss in the second quarter of 2018 decreased the Company's total realized price by \$0.74 per boe, compared to the realized gain in the second quarter of the prior year, which increased the Company's total realized price by \$0.23 per boe.

The Company recognized a realized hedging loss of \$0.3 million during the six months ended June 30, 2018, compared to a \$0.7 million gain realized in the same period of the prior year. The realized loss in the current year is due to strengthened oil prices.

The unrealized hedging loss of \$8.3 million for the three months ended June 30, 2018 represents the change in the unrealized risk management net asset position during the quarter. The unrealized hedging loss of \$13.9 million for the six months ended June 30, 2018 represents the change in the unrealized risk management net asset position during the first six months of 2018. This change is the result of both the realization of hedging gains in the period, changes related to contracts entered into during the period as well as changes to commodity prices. On June 30, 2018, the unrealized risk management net liability mark-to-market value was \$11.8 million.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2018, 2019 and 2020. The Company endeavors to hedge approximately 50 to 70% of its forecast production for the following year, and approximately 30 to 50% of its forecast production for the subsequent year. The Company's hedging strategy is intended to provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. A summary of Petrus' risk management contracts is included in note 8 of the Company's interim consolidated financial statements as at and for the period ended June 30, 2018. The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The average volume of oil hedged for the remainder of 2018 (2,025 bbl/d) represents 74% of second quarter total average liquids (oil and NGL) production. The 26,000 GJ/d of natural gas hedged for the remainder of 2018 represents 63% of second quarter average natural gas production.

The following table summarizes the average and minimum and maximum cap and floor prices for the 2018 to 2020 oil and natural gas contracts in place as at the date of this MD&A:

	2018					2019					2020				
	Q1	Q2	Q3	Q4	Avg. ⁽¹⁾	Q1	Q2	Q3	Q4	Avg. ⁽¹⁾	Q1	Q2	Q3	Q4	Avg. ⁽¹⁾
Oil hedged (bbl/d)	2,300	1,950	2,050	2,000	2,075	1,850	1,400	1,400	1,300	1,488	800	300	—	—	550
Avg. WTI cap price (\$/bbl)	65.80	66.24	66.95	66.31	66.31	67.68	67.13	69.26	68.76	68.16	70.20	74.85	—	—	71.47
Avg. WTI floor price (\$/bbl)	62.16	65.06	66.63	66.06	64.89	67.43	67.13	69.26	68.76	68.08	70.20	74.85	—	—	71.47
Natural gas hedged (GJ/d)	35,500	27,000	27,000	25,000	28,625	20,000	14,000	14,000	11,000	14,000	8,500	3,500	3,500	1,167	4,167
Avg. AECO 7A cap price (\$/GJ)	2.77	2.26	2.26	2.36	2.44	2.48	1.73	1.73	1.73	2.01	1.73	1.58	1.58	1.58	1.66
Avg. AECO 7A floor price (\$/GJ)	2.74	2.26	2.26	2.36	2.43	2.48	1.73	1.73	1.73	2.01	1.73	1.58	1.58	1.58	1.66

⁽¹⁾ The volumes and prices reported are the weighted average volumes and prices for the period.

OPERATING EXPENSE

The following table shows the Company's operating expense for the reporting periods shown:

Operating Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Operating expense, net ⁽¹⁾	3,841	5,156	8,001	8,935
Operating expense, net (\$/boe)	4.57	5.53	4.46	5.04

⁽¹⁾ Operating expense is presented net of processing income and overhead recoveries.

Operating expense (presented net of processing income and overhead recoveries) totaled \$3.8 million for the second quarter of 2018, a 26% decrease from the \$5.2 million recorded in the second quarter of the prior year. This change is attributable to the 10% decrease in production over the same time period as well as improved operating efficiencies. On a per boe basis, operating expense for the second quarter was 17% lower at \$4.57 per boe in 2018 compared to \$5.53 per boe in 2017. The decrease is due to Petrus' continued commitment to lower operating costs.

For the six months ended June 30, 2018, operating expense (presented net of processing income and overhead recoveries) totaled \$8.0 million, an 11% decrease from the \$8.9 million incurred in the comparable period of the prior year. The decrease is attributable to Petrus' improved operating cost structure and decreased activity related to well workover projects. During the first six months of 2017, Petrus incurred significantly higher non-routine workover expense, the majority of which was incurred in the Foothills operating area.

TRANSPORTATION EXPENSE

The following table shows transportation expense paid in the reporting periods:

Transportation Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Transportation expense	988	1,235	2,185	2,392
Transportation expense (\$/boe)	1.17	1.32	1.22	1.35

Petrus pays commodity and demand charges for transporting its gas on various pipeline systems. The Company also incurs trucking costs on the portion of its oil and natural gas liquids production that is not pipeline connected. Transportation expense totaled \$1.0 million or \$1.17 per boe in the second quarter of 2018 (\$1.2 million or \$1.32 per boe for the prior year comparative period).

On a six month basis, transportation expense totaled \$2.2 million, or \$1.22 per boe, which is 9% and 10% lower, respectively, than the costs incurred (\$2.4 million or \$1.35 per boe) in the prior year comparative period.

Overall, transportation expense, total and on a per boe basis, was lower during the second quarter and for the first six months of 2018 than the prior year comparative periods due to decreased production and trucking costs.

GENERAL AND ADMINISTRATIVE EXPENSE

The following table illustrates the Company's general and administrative ("G&A") expense which is shown net of capitalized costs directly related to exploration and development activities:

General and Administrative Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Gross general and administrative expense	1,749	2,495	4,158	4,720
Capitalized general and administrative and overhead recoveries	(377)	(1,448)	(1,356)	(2,791)
General and administrative expense	1,372	1,047	2,802	1,929
General and administrative expense (\$/boe)	1.63	1.12	1.56	1.09

The Company's general and administrative expense consisted of the following expenditures:

General and Administrative Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Personnel, consultants and directors	949	1,562	2,459	2,974
Office costs	665	763	1,143	1,285
Regulatory and public company expenses	135	170	556	461
Capitalized general and administrative expense and overhead recoveries	(377)	(1,448)	(1,356)	(2,791)
General and administrative expense	1,372	1,047	2,802	1,929

Second quarter 2018 G&A expense totaled \$1.4 million or \$1.63 per boe, compared to \$1.0 million or \$1.12 per boe in the second quarter of 2017. The increase from the prior year is primarily due to higher capital overhead recoveries recognized in the prior year as a result of higher capital activity in 2017 compared to 2018.

On a six month basis, G&A expense for the period ending June 30, 2018 totaled \$2.8 million or \$1.56 per boe compared to \$1.9 million or \$1.09 per boe for the prior year comparative period. The increase in 2018 is primarily due to higher capital overhead recoveries recognized in the prior year as a result of higher capital activity in 2017 compared to 2018, partially offset by lower personnel costs in 2018.



SHARE-BASED COMPENSATION EXPENSE

The following table illustrates the Company's share-based compensation expense which is shown net of capitalized costs directly related to exploration and development activities:

Share-Based Compensation Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Gross share-based compensation expense	165	194	355	335
Capitalized share-based compensation	(66)	(78)	(142)	(134)
Share-based compensation expense	99	116	213	201

Share-based compensation expense (net of capitalized portion) was \$0.1 million for the second quarter of 2018, which is consistent with the \$0.1 million recognized in the second quarter of the prior year.

On a six month basis, share-based compensation expense (net of capitalized portion) for the period ending June 30, 2018 was \$0.2 million, which is also consistent with the prior year comparative period (\$0.2 million).

FINANCE EXPENSE

The following table illustrates the Company's finance expense which includes cash and non-cash expenses:

Finance Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Interest expense	2,097	1,807	3,962	3,543
Total cash finance expense	2,097	1,807	3,962	3,543
Deferred financing costs	126	—	267	—
Accretion on decommissioning obligations	222	246	446	484
Total finance expense	2,445	2,053	4,675	4,027

The Company incurred total finance expense of \$2.4 million in the second quarter of 2018, comprised of \$0.2 million of non-cash accretion of its decommissioning obligations and \$2.1 million of cash interest expense and \$0.1 million of deferred financing fees, both related to the Revolving Credit Facility and Term Loan (as defined herein). In the second quarter of 2017, the Company incurred total finance expense of \$2.1 million, comprised of \$0.2 million in non-cash accretion of its decommissioning obligation and \$1.8 million cash interest expense.

The Company incurred total finance expense of \$4.7 million for the six month period ending June 30, 2018, compared to \$4.0 million for the prior year comparative period. The increase in 2018 is due to higher interest rates.

DEPLETION AND DEPRECIATION

The following table compares depletion and depreciation expense recorded in the reporting periods shown:

Depletion and Depreciation Expense (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Depletion and depreciation expense	10,494	13,314	22,113	24,931
Depletion and depreciation expense (\$/boe)	12.47	14.29	12.32	14.07

Depletion and depreciation expense is calculated on a unit-of-production (boe) basis. This fluctuates period to period primarily as a result of changes in the underlying proved plus probable reserve base and in the amount of costs subject to depletion and depreciation, including future development cost. Such costs are segregated and depleted on an area by area basis relative to the respective underlying proved plus probable reserve base.

Petrus recorded depletion and depreciation expense in the second quarter of 2018 of \$10.5 million or \$12.47 per boe, compared to the second quarter of 2017, when \$13.3 million or \$14.29 per boe was recorded. For the six month period ending June 30, 2018, the Company recorded \$22.1 million or \$12.32 per boe, compared to \$24.9 million or \$14.07 per boe for the prior year.



SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of common shares ("Common Shares") and an unlimited number of preferred shares ("Preferred Shares"). The Company has not issued any Preferred Shares. The following table details the number of issued and outstanding securities for the periods shown:

Share Capital (000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Weighted average Common Shares outstanding				
Basic	49,492	49,428	49,492	48,098
Fully diluted	49,492	49,428	49,492	48,140
Common Shares outstanding				
Basic	49,492	49,428	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,429
Stock options outstanding	2,934	2,751	2,934	2,751
Performance warrants outstanding	—	86	—	86

At June 30, 2018, the Company had 49,491,840 Common Shares and 2,933,990 stock options outstanding. The Company issued 549,900 stock options on May 28, 2018 at an exercise price of \$1.49.

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. At June 30, 2018, 130,038 (December 31, 2017 – 130,038) deferred share units were issued and outstanding.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2018, Petrus had two debt instruments outstanding. The first is a reserve-based, senior secured revolving credit facility with a syndicate of lenders, which is comprised of an operating facility and a syndicated term-out facility (together, the "Revolving Credit Facility" or "RCF"). The second is a subordinated secured term loan (the "Term Loan").

(a) Revolving Credit Facility

At June 30, 2018, the RCF was comprised of a \$20 million operating facility and a \$100 million syndicated term-out facility. Consent from the syndicate lenders and the Term Loan lender is required for total borrowings against the RCF exceeding \$105 million. The syndicated term-out facility has a revolving period that ends May 31, 2019 at which time it will either be renewed or converted to a one-year term facility. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company. In May 2018, Petrus completed the annual review of the RCF. The RCF syndicate of lenders agreed to maintain the Company's borrowing base of \$120 million until June 30, 2018 after which time, the borrowing base will decrease to \$110 million. Consent from the RCF syndicate of lenders and the Term Loan lender is required for total borrowings under the RCF to exceed \$105 million.

At June 30, 2018, the Company had a \$0.4 million letter of credit outstanding against the RCF (December 31, 2017 – \$0.3 million) and had drawn \$95.3 million against the RCF (December 31, 2017 – \$0.3 million letter of credit and \$97.6 million outstanding against the RCF).

The amount of the RCF is subject to a borrowing base review performed on a semi-annual basis by the lenders, based primarily on reserves and commodity prices estimated by the lenders as well as other factors. In addition, asset dispositions require majority lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At June 30, 2018, the Company had a \$35 million (December 31, 2017 – \$35 million) Term Loan outstanding (excluding \$0.8 million of deferred finance fees), which is due October 8, 2020. The Term Loan bears interest which is due and payable monthly and accrues at a per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company.

Financial Covenants

The RCF and the Term Loan carry financial covenants that are described in note 6 of the Company's June 30, 2018 interim consolidated financial statements. The Company was in compliance with all financial covenants at June 30, 2018.

Liquidity Risk

Liquidity risk relates to the risk the Company will encounter difficulty in meeting obligations associated with its financial liabilities that are settled by cash as they become due. The Company's approach to managing liquidity risk is to ensure, as much as possible, that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions without incurring unacceptable losses.



or risking harm to the Company's reputation. The financial liabilities on its balance sheet consist of bank indebtedness, accounts payable, long term debt and risk management liabilities. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future funds flow.

Typically the Company ensures that it has sufficient cash on demand to meet expected operational expenses for a normal period. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th day of each month.

As at June 30, 2018, the Company had a working capital deficiency (excluding the risk management asset or liability) of \$5.7 million, primarily related to the \$11.7 million in accounts payable. The Company plans to address this working capital deficiency by using its funds flow and available credit facilities. The next scheduled borrowing base redetermination date for the RCF is on or before October 31, 2018. Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through funds flow and available credit capacity from its RCF.

The following are the contractual maturities of financial liabilities as at June 30, 2018:

\$000s	Total	< 1 year	1-5 years
Accounts payable	11,657	11,657	—
Risk management liability	11,839	7,858	3,981
Bank indebtedness and long term debt ⁽¹⁾	133,603	3,303	130,300
Total	157,099	22,818	134,281

⁽¹⁾Excludes deferred finance fees.

The commitments for which the Company is responsible are as follows:

\$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	1,134	716	418	—
Firm service transportation	20,020	1,073	12,501	6,446
Total commitments	21,154	1,789	12,919	6,446

Risk Management

Petrus is engaged in the acquisition, development, exploration and exploitation of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute Petrus' business strategy. Financial risks associated with the oil and natural gas industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, regulatory, environment and safety concerns.

For a more in-depth discussion of risk management, see notes 8 and 13 of the Company's June 30, 2018 interim consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled \$1.7 million in the second quarter of 2018, compared to \$18.9 million in the second quarter of the prior year. For the six months ended June 30, 2018, Petrus invested \$7.8 million compared to \$37.8 million in the prior year. The decrease in capital spending is related to decreased capital activity as a result of lower natural gas commodity pricing. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Drill and complete	869	11,332	3,292	26,274
Oil and gas equipment	551	6,460	2,182	9,770
Land and lease	27	451	1,493	583
Office	—	92	—	128
Capitalized general and administrative	298	568	830	1,056
Total Capital Expenditures	1,745	18,903	7,797	37,811
Gross (net) wells spud	1 (0.2)	3 (2.2)	2 (0.7)	11 (8.1)

The following table summarizes the acquisitions and dispositions for the reporting periods indicated:



Acquisitions and Dispositions (\$000s)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Acquisitions	18	—	—	8,818
Dispositions	(287)	—	(387)	—
Total Acquisitions and Dispositions	(269)	—	(387)	8,818

During the three and six months ended June 30, 2018, Petrus acquired other exploration and evaluation and petroleum and natural gas properties and equipment of \$0.02 million and \$1.3 million, respectively (three and six month periods ending June 30, 2017 were \$Nil and \$8.8 million, respectively). During the second quarter of 2018, Petrus divested non-core assets for approximately \$0.3 million (\$Nil in the prior year comparative periods).

SUMMARY OF QUARTERLY RESULTS

(\$000s unless otherwise noted)	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016
Average Production								
Natural gas (mcf/d)	39,126	45,543	46,625	45,550	42,392	40,332	37,327	30,009
Oil (bbl/d)	1,484	1,530	1,854	1,877	2,015	1,542	1,452	1,419
NGLs (bbl/d)	1,241	1,475	1,086	1,098	1,160	1,067	922	680
Total (boe/d)	9,246	10,596	10,711	10,567	10,240	9,331	8,595	7,100
Total (boe)	841,316	953,598	985,388	972,140	931,821	839,746	790,806	653,215
Financial Results								
Oil and natural gas revenue	19,321	25,301	23,243	18,299	26,753	22,274	21,409	13,805
Royalty expense	(2,137)	(4,674)	(3,000)	(2,656)	(4,306)	(3,309)	(2,787)	(1,951)
Net oil and natural gas revenue	17,184	20,627	20,243	15,643	22,447	18,965	18,622	11,854
Transportation expense	(988)	(1,197)	(1,233)	(1,255)	(1,235)	(1,157)	(1,187)	(971)
Operating expense	(3,841)	(4,160)	(4,744)	(5,271)	(5,155)	(3,780)	(2,867)	(3,945)
Operating netback	12,355	15,270	14,266	9,117	16,057	14,028	14,568	6,938
Realized gain (loss) on derivatives	(625)	298	1,210	1,829	212	482	783	2,652
Other income	103	—	—	—	—	—	—	—
General & administrative expense	(1,372)	(1,430)	(266)	(1,059)	(1,047)	(882)	(2,991)	(1,107)
Cash finance expense	(2,097)	(1,865)	(1,515)	(1,936)	(1,807)	(1,736)	(2,043)	(2,512)
Decommissioning expenditures	—	(168)	(611)	(224)	(957)	(160)	(508)	(28)
Corporate netback	8,364	12,105	13,084	7,727	12,458	11,732	9,809	5,943
Oil and natural gas revenue	19,321	25,301	23,243	18,299	26,753	22,274	21,409	13,805
Per share - basic	0.39	0.51	0.47	0.37	0.54	0.48	0.47	0.30
Per share - fully diluted	0.39	0.51	0.47	0.37	0.54	0.47	0.47	0.30
Net income (loss)	(10,615)	(5,684)	(67,095)	(50,696)	(781)	7,311	(11,842)	(4,702)
Per share - basic	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)	(0.10)
Per share - fully diluted	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)	(0.10)
Common shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,428	49,428	49,428	45,349	45,349
Fully diluted	49,492	49,492	49,492	49,428	49,428	52,664	45,349	45,349
Weighted avg. shares outstanding (000s)								
Basic	49,492	49,492	49,456	49,428	49,428	46,754	45,349	45,349
Fully diluted	49,492	49,492	49,456	49,428	49,428	46,989	45,349	45,349
Total assets	330,359	343,161	353,445	409,078	465,794	460,095	439,967	448,404
Net debt	(135,111)	(142,238)	(148,066)	(137,531)	(137,069)	(130,624)	(124,915)	(124,310)

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and cash flows are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus' average quarterly production increased from 7,100 boe/d in the third quarter of 2016 to 9,246 boe/d in the second quarter of 2018. The 30% production increase is attributable to the Company's drilling program in the Ferrier area.

Commodity price improvements enable higher reinvestment in exploration, development and acquisition activities in future periods as they increase the cash flows from operating activities. Commodity price reductions reduce revenues received and can challenge the economics of the Company's development program as the quantity of reserves may not be economically recoverable. Petrus' investment in its assets, and its ability to replace and grow reserve volumes, will be dependent on its ability to obtain debt and equity financing as well as the funds it receives from operations.



CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below. The Company's critical accounting estimates can be read in note 2 to the Company's audited consolidated financial statements as at and for the year ended December 31, 2017.

OTHER FINANCIAL INFORMATION

Significant accounting policies

The Company's significant accounting policies can be read in note 3 of the Company's audited consolidated financial statements as at and for the year ended December 31, 2017.

New standards and interpretations

The Company's discussion on new standards and interpretations can be read in note 2 of the Company's interim financial statements as at and for the period ended June 30, 2018.

Internal Control over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; 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 period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on April 1, 2018 and ending on June 30, 2018 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

NON-GAAP FINANCIAL MEASURES

This MD&A makes reference to the terms "operating netback", "corporate netback", "net debt" and "net debt to funds flow." These indicators are not recognized measures under GAAP (IFRS) and do not have a standardized meaning prescribed by GAAP (IFRS). Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses these terms for the reasons set forth below.

Operating Netback

Operating netback is a common non-GAAP financial measure used in the oil and gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and gas lease level. The most directly comparable GAAP measure to operating netback is funds flow. Operating netback is calculated as oil and natural gas revenue less royalties, operating and transportation expenses. It is presented on an absolute value and per unit basis.

Corporate Netback

Corporate netback is also a common non-GAAP financial measure used in the oil and gas industry which evaluates the Company's profitability at the corporate level. Management believes corporate netback provides information to assist a reader in understanding the Company's profitability relative to current commodity prices. It is calculated as the operating netback less general and administrative expense, finance expense, decommissioning expenditures, plus the net realized gain (loss) on financial derivatives. It is presented on an absolute value and per unit basis. The most directly comparable GAAP measure to corporate netback is funds flow.

	Three months ended Jun. 30, 2018		Three months ended Jun. 30, 2017		Six months ended Jun. 30, 2018		Six months ended Jun. 30, 2017	
	\$000s	\$/boe	\$000s	\$/boe	\$000s	\$/boe	\$000s	\$/boe
Oil and natural gas revenue	19,321	22.97	26,753	28.72	44,622	24.86	49,027	27.67
Royalty expense	(2,137)	(2.54)	(4,306)	(4.62)	(6,811)	(3.79)	(7,615)	(4.30)
Net oil and natural gas revenue	17,184	20.43	22,447	24.10	37,811	21.07	41,412	23.37
Transportation expense	(988)	(1.17)	(1,235)	(1.32)	(2,185)	(1.22)	(2,392)	(1.35)
Operating expense	(3,841)	(4.57)	(5,155)	(5.53)	(8,001)	(4.46)	(8,935)	(5.04)
Operating netback	12,355	14.69	16,057	17.25	27,625	15.39	30,085	16.98
Realized gain (loss) on financial derivatives	(625)	(0.74)	212	0.23	(327)	(0.18)	694	0.39
Other income	103	0.12	—	—	103	0.06	—	—
General & administrative expense	(1,372)	(1.63)	(1,047)	(1.12)	(2,802)	(1.56)	(1,929)	(1.09)
Cash finance expense	(2,097)	(2.49)	(1,807)	(1.94)	(3,962)	(2.21)	(3,543)	(2.00)
Decommissioning expenditures	—	—	(957)	(1.03)	(168)	(0.19)	(1,117)	(0.63)
Corporate netback and funds flow	8,364	9.95	12,458	13.39	20,469	11.31	24,190	13.65

Net Debt

Net debt is a non-GAAP financial measure and is calculated as current assets (excluding unrealized financial derivative assets) less current liabilities (excluding unrealized financial derivative liabilities) and long term debt. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. There is no GAAP measure that is reasonably comparable to net debt.

(\$000s)	As at June 30, 2018	As at December 31, 2017
Current assets adjusted for unrealized financial instruments	9,316	13,042
Less: current liabilities adjusted for unrealized financial instruments	(14,960)	(29,201)
Less: long term debt	(129,467)	(131,907)
Net debt	(135,111)	(148,066)

Net Debt to Funds Flow

Net debt to funds flow is calculated as the period ending net debt divided by the trailing quarter funds flow (annualized).

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2017, which includes disclosure of our oil and natural gas reserves and other oil and natural gas information in accordance with NI 51-101, is contained in the AIF. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.



ADVISORIES

Basis of Presentation

Financial data presented above has largely been derived from the Company's financial statements, prepared in accordance with GAAP which require publicly accountable enterprises to prepare their financial statements using IFRS. Accounting policies adopted by the Company are set out in the notes to the audited financial statements as at and for the twelve months ended December 31, 2017. The reporting and the measurement currency is the Canadian dollar. All financial information is expressed in Canadian dollars, unless otherwise stated.

Forward-Looking Statements

Certain information regarding Petrus set forth in this MD&A contains forward-looking statements within the meaning of applicable securities law, that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. Such statements represent Petrus' internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital investment, anticipated future debt, production, revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Petrus believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Petrus' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Petrus.

In particular, forward-looking statements included in this MD&A include, but are not limited to, expectations regarding the focus of and timing of capital expenditures; Petrus' drilling program; expected debt repayment amounts; the performance characteristics of the Company's crude oil, NGL and natural gas properties including estimated production; crude oil, NGL and natural gas production levels and product mix; the availability of funds flow; sources of funding for capital expenditures; the use of funds flow and available credit facilities to address working capital deficiency; the growth of Petrus and the availability of the full amount of the revolving credit facility; the treatment of the revolving credit facility following the end of the revolving period; Petrus' ability to fund its financial liabilities; the size of, and future net revenues from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; Petrus' future operating and financial results; supply and demand for crude oil, NGL and natural gas; future royalty rates; drilling, development and completion plans and the results therefrom; and treatment under governmental regulatory regimes and tax laws. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

These forward-looking statements are subject to numerous risks and uncertainties, most of which are beyond the Company's control, including the impact of general economic conditions; volatility in market prices for crude oil, NGL and natural gas; industry conditions; currency fluctuation; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; stock market volatility; ability to access sufficient capital from internal and external sources; completion of the financing on the timing planned and the receipt of applicable approvals; and the other risks. With respect to forward-looking statements contained in this MD&A, Petrus has made assumptions regarding: future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment and services; effects of regulation by governmental agencies; and future operating costs. Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom. Readers are cautioned that the foregoing lists of factors are not exhaustive.

These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

BOE Presentation

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. Petrus uses the 6:1 boe measure which is the approximate energy equivalence of the two commodities at the burner tip. Boe's do not represent an economic value equivalence at the wellhead and therefore may be a misleading measure if used in isolation.



Abbreviations

<i>000's</i>	<i>thousand dollars</i>
<i>\$/bbl</i>	<i>dollars per barrel</i>
<i>\$/boe</i>	<i>dollars per barrel of oil equivalent</i>
<i>\$/GJ</i>	<i>dollars per gigajoule</i>
<i>\$/mcf</i>	<i>dollars per thousand cubic feet</i>
<i>bbl</i>	<i>barrel</i>
<i>bbl/d</i>	<i>barrels per day</i>
<i>boe</i>	<i>barrel of oil equivalent</i>
<i>boe/d</i>	<i>barrel of oil equivalent per day</i>
<i>GJ</i>	<i>gigajoule</i>
<i>GJ/d</i>	<i>gigajoules per day</i>
<i>mcf</i>	<i>thousand cubic feet</i>
<i>mcf/d</i>	<i>thousand cubic feet per day</i>
<i>mmcf/d</i>	<i>million cubic feet per day</i>
<i>NGLs</i>	<i>natural gas liquids</i>
<i>WTI</i>	<i>West Texas Intermediate</i>

