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 nine months ended September 30, 2018. The MD&A is dated November 8, 2018 and should be read in conjunction with the Company's September 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 Sept. 30, 2018	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017
Average Production					
Natural gas (mcf/d)	33,461	45,550	39,126	45,543	46,625
Oil (bbl/d)	1,243	1,877	1,484	1,530	1,854
NGLs (bbl/d)	1,519	1,098	1,241	1,475	1,086
Total (boe/d)	**8,338**	**10,567**	**9,246**	**10,596**	**10,711**
Total (boe)	**767,095**	**972,140**	**841,316**	**953,598**	**985,388**
Natural gas sales weighting	67%	72%	71%	72%	73%
Realized Prices					
Natural gas ($/mcf)	1.50	1.66	1.24	2.18	1.90
Oil ($/bbl)	77.24	51.23	75.29	73.91	66.10
NGLs ($/bbl)	45.27	24.79	41.53	46.50	38.00
Total realized price ($/boe)	**25.79**	**18.82**	**22.92**	**26.50**	**23.56**
Royalty income	0.32	0.01	0.05	0.03	0.03
Royalty expense	(3.12)	(2.73)	(2.54)	(4.90)	(3.04)
Net oil and natural gas revenue ($/boe)	**22.99**	**16.10**	**20.43**	**21.63**	**20.55**
Operating expense	(4.95)	(5.42)	(4.57)	(4.36)	(4.81)
Transportation expense	(0.98)	(1.29)	(1.17)	(1.26)	(1.25)
Operating netback [1] ($/boe)	**17.06**	**9.39**	**14.69**	**16.01**	**14.49**
Realized gain (loss) on derivatives	(2.69)	1.88	(0.74)	0.31	1.23
Other income	0.08	—	0.12	—	—
General & administrative expense	(1.72)	(1.09)	(1.63)	(1.50)	(0.27)
Cash finance expense	(2.53)	(1.99)	(2.49)	(1.96)	(1.54)
Decommissioning expenditures	(0.20)	(0.23)	—	(0.23)	(0.62)
Corporate netback [1] ($/boe)	**10.00**	**7.96**	**9.95**	**12.63**	**13.29**

FINANCIAL ($000s except per share)	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017
Oil and natural gas revenue	20,030	18,299	19,321	25,301	23,243
Net loss	(8,048)	(50,696)	(10,615)	(5,684)	(67,095)
Net loss per share					
Basic	(0.16)	(1.03)	(0.21)	(0.11)	(1.36)
Fully diluted	(0.16)	(1.03)	(0.21)	(0.11)	(1.36)
Funds flow	**7,685**	**7,727**	**8,364**	**12,105**	**13,084**
Funds flow per share					
Basic	0.16	0.16	0.17	0.24	0.26
Fully diluted	0.16	0.16	0.17	0.24	0.26
Capital expenditures	**3,637**	**13,055**	**1,745**	**6,056**	**21,885**
Net acquisitions (dispositions)	(50)	(4,866)	(269)	(123)	789
Weighted average shares outstanding					
Basic	49,492	49,428	49,492	49,492	49,456
Fully diluted	49,492	49,428	49,492	49,492	49,456
As at period end					
Common shares outstanding (000s)					
Basic	49,492	49,428	49,492	49,492	49,492
Fully diluted	49,492	49,428	49,492	49,492	49,492
Total assets	322,335	409,078	330,359	343,161	353,445
Non-current liabilities	170,908	191,145	172,757	174,634	173,272
Net debt [1]	**131,603**	**137,531**	**135,111**	**142,238**	**148,066**

[1] *Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*

OPERATIONS UPDATE

Production

Third quarter average production by area was as follows:

For the three months ended September 30, 2018	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	24,458	2,462	6,542	33,462
Oil (bbl/d)	674	164	405	1,243
NGLs (bbl/d)	1,322	8	189	1,518
Total (boe/d)	**6,072**	**582**	**1,684**	**8,338**
Natural gas sales weighting	***67%***	***71%***	***65%***	***67%***

Third quarter average production was 8,338 boe/d (67% natural gas) in 2018 compared to 10,567 boe/d (72% natural gas) in the third quarter of 2017. The 21% decrease is due to certain dry gas production in the Foothills area which was shut-in due to uneconomic gas prices. The production decrease is also attributable to natural production declines. Petrus strategically deferred its capital development until the second half of 2018 in order to permit debt repayment early in the year.

Capital Development[1]

In response to the commodity price outlook for natural gas, the Company set out in 2018 to improve its financial position and direct excess funds flow to debt repayment, targeting debt reduction of $10 to $15 million. In the first nine months of 2018, Petrus reduced its net debt by $16.5 million or 11%. The second element of the Company's 2018 plan targeted to drill Cardium light oil wells in Ferrier with budgeted capital of $25 to $30 million. The Company's development program recommenced during the third quarter as planned and total capital invested in the first nine months of 2018 has been $11.5 million. Petrus drilled 5 (2.9 net) wells during the second half of 2018 for a total of 7 (3.6 net) drilled or participated in to date in 2018. The completion operations for the 5 recent wells commenced in early November and the wells are expected to be on stream by year end[2]. The Company expects that the remaining capital program will be funded by funds flow and working capital.

Production Optimization

During the third quarter, Petrus initiated additional deep cut processing of certain natural gas production in order to increase its natural gas liquids yield. In the current commodity price environment, the increased NGL yield optimizes the netback. Petrus' total liquids production increased from 29% in the second quarter of 2018 to 33% in the third quarter of 2018 despite no new oil production brought on stream.

CREDIT FACILITY UPDATE

The 2018 semi-annual review of the Company's Revolving Credit Facility ("RCF") has been completed and the RCF syndicate of lenders maintained the Company's borrowing base at $110 million. The Company's $35 million second lien term loan ("Term Loan") also remains unchanged following the semi-annual RCF review. The Term Loan is due October 8, 2020 and bears interest at the Canadian Dealer Offered Rate (CDOR) plus 700 basis points. The average Term Loan interest rate for the third quarter of 2018 was 8.8%.

BOARD OF DIRECTORS

Mr. Brian Minnehan and Mr. Jeffrey Zlotky, both nominees of Wingren B.V., have resigned as directors of Petrus. The Board of Directors, management and staff of Petrus would like to thank Messrs. Minnehan and Zlotky for their leadership, hard work, commitment, and service to Petrus and its Board of Directors.

[1] Refer to "Advisories - Forward-Looking Statements"in the Management's Discussion & Analysis attached hereto.

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017
Average production					
Natural gas (mcf/d)	33,461	45,550	39,126	45,543	46,625
Oil (bbl/d)	1,243	1,877	1,484	1,530	1,854
NGLs (bbl/d)	1,519	1,098	1,241	1,475	1,086
Total (boe/d)	**8,338**	**10,567**	**9,246**	**10,596**	**10,711**
Total (boe)	**767,095**	**972,140**	**841,316**	**953,598**	**985,388**
Revenue ($000s)					
Natural Gas	4,630	6,939	4,432	8,918	8,149
Oil	8,828	8,848	10,159	10,175	11,273
NGLs	6,326	2,504	4,692	6,175	3,796
Royalty revenue	246	8	38	33	25
Oil and natural gas revenue	**20,030**	**18,299**	**19,321**	**25,301**	**23,243**
Average realized prices					
Natural gas ($/mcf)	1.50	1.66	1.24	2.18	1.90
Oil ($/bbl)	77.24	51.23	75.29	73.91	66.10
NGLs ($/bbl)	45.27	24.79	41.53	46.50	38.00
Total realized price ($/boe)	25.79	18.82	22.92	26.50	23.56
Hedging gain (loss) ($/boe)	(2.69)	1.88	(0.74)	0.31	1.23
Total price including hedging ($/boe)	**23.10**	**20.70**	**22.18**	**26.81**	**24.79**

Average benchmark prices	Three months ended Sept. 30, 2018	Three months ended Sept. 30, 2017	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018	Three months ended Dec. 31, 2017
Natural gas					
AECO 5A ($/GJ)	1.13	1.38	1.12	1.97	1.60
AECO 7A ($/GJ)	1.28	1.93	0.97	1.76	1.86
Crude Oil					
Edm Lt. ($/bbl)	79.65	57.08	78.91	72.28	66.93
Foreign Exchange					
US$/C$	0.77	0.80	0.78	0.80	0.78

FUNDS FLOW AND NET LOSS

Petrus generated funds flow of $7.7 million in the third quarter of 2018, which is consistent to the $7.7 million generated in the third quarter of 2017. On a nine month basis, funds flow was $28.2 million compared to $31.9 million in the prior year. The 12% decrease is due to 45% lower natural gas pricing (AECO 7A monthly index), offset by 11% lower operating expenses and 27% higher light oil pricing (Edm CAD$).

Petrus reported a net loss of $8.0 million in the third quarter of 2018, compared to a net loss of $50.7 million in the third quarter of the prior year. The lower net loss is primarily due to the recognition of an impairment loss in the third quarter of the prior year. On a nine month basis, the Company generated a net loss of $44.2 million for the nine months ended September 30, 2017 compared to a net loss of $24.3 million for the nine months ended September 30, 2018. The accounting for the unrealized hedging on financial derivatives had a material impact on the earnings; during the nine months ended September 30, 2017, the Company recognized an unrealized gain of $12.1 million whereas during the nine months ended September 30, 2018, a $17.9 million unrealized loss was recorded. The differences are due to changes in commodity prices at September 30 of the respective years.

($000s except per share)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Funds flow	**7,685**	**7,727**	**28,154**	**31,918**
Funds flow per share - basic	0.16	0.16	0.57	0.66
Funds flow per share - fully diluted	0.16	0.16	0.57	0.65
Net loss	**(8,048)**	**(50,696)**	**(24,347)**	**(44,167)**
Net loss per share - basic	(0.16)	(1.03)	(0.49)	(0.92)
Net loss per share - fully diluted	(0.16)	(1.03)	(0.49)	(0.92)
Common shares outstanding (000s)				
Basic	49,492	49,428	49,492	49,428
Fully diluted	49,492	49,428	49,492	49,428
Weighted average shares outstanding (000s)				
Basic	49,492	49,428	49,492	48,098
Fully diluted	49,492	49,428	49,492	49,098

OIL AND NATURAL GAS REVENUE

Average production for the third quarter of 2018 was 8,338 boe/d (67% natural gas), 21% lower than the 10,567 boe/d (72% natural gas) average production for the third quarter of the prior year. The 21% decrease is due to certain dry gas production in the Foothills area which was shut-in due to uneconomic gas prices. The production decrease is also attributable to natural production declines. Despite lower production, total oil and natural gas revenue increased from $18.3 million in 2017 to $20.0 million in 2018. The 9% increase is due to higher realized oil and natural gas liquids prices.

Average production for the first nine months of 2018 was 9,384 boe per day (70% natural gas), compared to 10,050 boe per day (71% natural gas) for the prior year comparative period. Total oil and natural gas revenue decreased from $67.3 million in the first nine months of 2017 to $64.7 million in the nine months ended September 30, 2018 mainly due to 7% lower production and 45% lower natural gas pricing.

Natural gas

During the three and nine months ended September 30, 2018, the average benchmark natural gas price in Canada (AECO 7A monthly index) decreased by 34% and 45%, respectively, from the prior year comparative periods (average price of $1.35 per mcf in the third quarter of 2018 compared to $2.04 per mcf in the third quarter of the prior year, and $1.41 per mcf for the first nine months of 2018, compared to $2.58 per mcf for the prior year comparative period).

The Company's average realized natural gas price during the third quarter of 2018 was $1.50 per mcf, compared to $1.66 per mcf in the third quarter of 2017, which represents a 10% decrease. Natural gas revenue for the third quarter of 2018 was $4.6 million and production of 3,078,426 mcf accounting for approximately 67% of third quarter production volume and 23% of oil and natural gas revenue, compared to revenue of $6.9 million and production of 4,190,541 mcf accounting for approximately 72% of third quarter production volume and 38% 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 third quarter of 2018.

Natural gas revenue for the first nine months of 2018 was $18.0 million and production of 10,737,795 mcf accounted for approximately 70% of production volume in the period and 28% of oil and natural gas revenue, compared to revenue of $30.0 million and production of 11,678,072 mcf for 72% of production volume and 45% of oil and natural gas revenue in the prior year comparative period. The decrease is due to lower natural gas prices.

Crude oil and condensate

Edmonton Light Sweet crude oil prices increased 40% from the third quarter of 2017 to the third quarter of 2018 (an average price of $79.65 per bbl for the third quarter of 2018 compared to an average price of $57.08 per bbl for the prior year comparative period). Prices increased 27% from the first nine months of 2017 to the first nine months of 2018 ($76.95 per bbl in 2018 compared to an average of $60.73 per bbl in the prior year comparative period).

Similarly, the average realized price of Petrus' crude oil and condensate was $77.24 per bbl for the third quarter of 2018 compared to $51.23 per bbl for the same period in the prior year.

Oil and condensate revenue for the third quarter of 2018 was $8.8 million and production of 114,291 bbl accounted for approximately 15% of total production volume and 45% of oil and natural gas revenue, compared to revenue of $8.8 million and production of 172,705 bbl accounted for approximately 18% of total production volume and 48% of oil and natural gas revenue in the third quarter of the prior year.

Oil and condensate revenue for the first nine months of 2018 was $29.2 million and production of 386,889 bbl accounted for approximately 15% of total production volume and 45% of oil and natural gas revenue, compared to revenue of $28.4 million and production of 494,826 bbl for 18% of total production volume and 42% of oil and natural gas revenue in the first nine 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 third quarter of 2018, the overall realized NGL price averaged $45.27 per bbl, compared to $24.79 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.

During the third quarter, Petrus initiated additional deep cut processing of certain natural gas production in order to increase its natural gas liquids yield. In the current commodity price environment, the increased NGL yield optimizes the netback. Petrus' total liquids production increased from 29% in the second quarter of 2018 to 33% in the third quarter of 2018 despite no new oil production brought on stream.

NGL revenue for the third quarter of 2018 was $6.3 million and production of 139,733 bbl accounted for approximately 18% of production volume and 32% of oil and natural gas revenue, compared to revenue of $2.5 million and production of 101,010 bbl accounted for approximately 10% of production volume and 14% of oil and natural gas revenue for the third quarter of the prior year.

NGL revenue for the first nine months of 2018 was $17.2 million and production of 386,889 bbl accounted for approximately 15% of production volume and 27% of oil and natural gas revenue in the period, compared to revenue of $8.9 million and production of 302,535 bbl for 11% of production volume and 13% of oil and natural gas revenue in the first nine 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Crown	**684**	819	**3,193**	4,315
Percent of production revenue	**3%**	5%	**5%**	6%
Gross overriding	**1,707**	1,836	**6,009**	5,955
Total	**2,391**	**2,655**	**9,202**	**10,270**

Total royalty expense (net of royalty allowances and incentives) decreased from $2.7 million in the third quarter of 2017 to $2.4 million in the third quarter of 2018 primarily due to 21% lower production and prior period Gas Cost Allowance ("GCA") adjustments which reduced the reported expense in the third quarter.

On a nine month basis, total royalty expense (net of royalty allowances and incentives) decreased from $10.3 million in 2017 to $9.2 million in 2018. The decrease is due to the lower natural gas revenue compared to the prior year.

Gross overriding royalties decreased from $1.8 million in the third quarter of 2017 to $1.7 million in the third quarter of 2018, due to lower natural gas prices. Gross overriding royalties were $6.0 million for the nine months ended September 30, 2018, which is consistent with the prior year.

RISK MANAGEMENT

The Company utilizes financial derivative contracts to mitigate commodity price risk and provide stability and sustainability to the Company's economic returns, funds flow and capital development plan. 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Realized hedging gain (loss)	**(2,061)**	1,829	**(2,388)**	2,523
Unrealized hedging gain (loss)	**(3,997)**	3,715	**(17,860)**	12,139
Net gain (loss) on derivatives	**(6,058)**	**5,544**	**(20,248)**	**14,662**

The Company recognized a realized hedging loss of $2.1 million during the third quarter of 2018, compared to a $1.8 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 partially offset by lower natural gas prices. The realized loss in the third quarter of 2018 decreased the Company's total realized price by $2.69 per boe, compared to the realized gain in the third quarter of the prior year, which increased the Company's total realized price by $1.88 per boe.

The Company recognized a realized hedging loss of $2.4 million during the nine months ended September 30, 2018, compared to a $2.5 million gain realized in the same period of the prior year. The realized loss in the current year is due to strengthened oil prices whereas in the prior year the gain was due to weak natural gas prices.

The unrealized hedging loss of $4.0 million for the three months ended September 30, 2018 represents the change in the unrealized risk management net asset position during the quarter. The unrealized hedging loss of $17.9 million for the nine months ended September 30, 2018 represents the change in the unrealized risk management net asset position during the first nine 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 September 30, 2018, the unrealized risk management net liability mark-to-market value was $15.8 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 September 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 (1,800 bbl/d) represents 62% of third quarter total average liquids (oil and NGL) production. The 25,667 GJ/d of natural gas hedged for the remainder of 2018 represents 71% of third 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	1,800	**2,025**	1,650	1,400	1,400	1,650	**1,525**	1,150	750	550	350	**700**
Avg. WTI cap price ($/bbl)	65.80	66.24	66.95	66.94	**66.45**	68.46	67.13	69.26	70.45	**68.88**	72.18	76.92	78.81	76.70	**75.32**
Avg. WTI floor price ($/bbl)	62.16	65.06	66.63	66.66	**64.99**	68.17	67.13	69.26	70.45	**68.80**	72.18	76.92	78.81	76.70	**75.32**
Natural gas hedged (GJ/d)	35,500	27,000	27,000	25,667	**28,792**	21,000	14,333	14,000	11,000	**15,083**	9,500	3,500	3,500	1,167	**4,417**
Avg. AECO 7A cap price ($/GJ)	2.77	2.26	2.26	2.36	**2.44**	2.47	1.74	1.73	1.74	**1.99**	1.74	1.58	1.58	1.58	**1.67**
Avg. AECO 7A floor price ($/GJ)	2.74	2.26	2.26	2.36	**2.43**	2.47	1.74	1.73	1.74	**1.99**	1.74	1.58	1.58	1.58	**1.67**

[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 ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Operating expense, net [1]	**3,800**	5,271	**11,801**	14,206
Operating expense, net ($/boe)	**4.95**	5.42	**4.61**	5.18

[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 third quarter of 2018, a 28% decrease from the $5.3 million recorded in the third quarter of the prior year. This change is attributable to the 21% decrease in production over the same time period as well as improved operating efficiencies. On a per boe basis, operating expense for the third quarter was 9% lower at $4.95 per boe in 2018 compared to $5.42 per boe in 2017. The decrease is due to Petrus' optimization of operating costs through facility ownership and control.

For the nine months ended September 30, 2018, operating expense (presented net of processing income and overhead recoveries) totaled $11.8 million, a 17% decrease from the $14.2 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 nine months of 2017, Petrus incurred significantly higher non-routine workover expense, the majority of which was incurred in the Foothills non-core operating area.

TRANSPORTATION EXPENSE

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

Transportation Expense ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Transportation expense	**749**	1,255	**2,934**	3,647
Transportation expense ($/boe)	**0.98**	1.29	**1.15**	1.33

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 $0.7 million or $0.98 per boe in the third quarter of 2018 ($1.3 million or $1.29 per boe for the prior year comparative period). The lower transportation expense is related to the 21% decrease in production from the third quarter of 2017 to the third quarter of 2018.

On a nine month basis, transportation expense totaled $2.9 million, or $1.15 per boe, compared to $3.6 million or $1.33 per boe in the prior year comparative period. The decrease is related to the 7% decrease in production from the nine months ended September 30, 2018 compared to the prior year comparative period.

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 ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Gross general and administrative expense	**1,823**	2,388	**5,981**	7,108
Capitalized general and administrative and overhead recoveries	**(506)**	(1,329)	**(1,862)**	(4,120)
General and administrative expense	**1,317**	**1,059**	**4,119**	**2,988**
General and administrative expense ($/boe)	**1.72**	**1.09**	**1.61**	**1.09**

The Company's G&A expense consisted of the following expenditures:

General and Administrative Expense ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Personnel, consultants and directors	**903**	1,514	**3,362**	4,488
Office costs	**792**	804	**1,935**	2,092
Regulatory and public company expenses	**128**	70	**684**	528
Capitalized general and administrative expense and overhead recoveries	**(506)**	(1,329)	**(1,862)**	(4,120)
General and administrative expense	**1,317**	**1,059**	**4,119**	**2,988**

Third quarter 2018 G&A expense totaled $1.3 million or $1.72 per boe, compared to $1.1 million or $1.09 per boe in the third 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. The increase on a per boe basis is also due to lower production in 2018 compared to the prior year.

On a nine month basis, G&A expense for the period ending September 30, 2018 totaled $4.1 million or $1.61 per boe compared to $3.0 million or $1.09 per boe for the prior year comparative period. The increase in 2018 G&A 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Gross share-based compensation expense	**174**	209	**529**	545
Capitalized share-based compensation	**(70)**	(84)	**(212)**	(218)
Share-based compensation expense	**104**	**125**	**317**	**327**

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

On a nine month basis, share-based compensation expense (net of capitalized portion) for the period ending September 30, 2018 was $0.3 million, which is also consistent with the prior year comparative period ($0.3 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Interest expense	**1,940**	1,936	**5,902**	5,478
Foreign exchange loss (gain)	**1**	—	**1**	1
Total cash finance expense	**1,941**	1,936	**5,903**	5,479
Deferred financing costs	**196**	—	**463**	—
Accretion on decommissioning obligations	**217**	240	**663**	724
Total finance expense	**2,354**	**2,176**	**7,029**	**6,203**

The Company incurred total finance expense of $2.4 million in the third quarter of 2018, comprised of $0.2 million of non-cash accretion of its decommissioning obligations, $1.9 million of cash interest expense and $0.2 million of amortization of deferred financing fees, both of which are related to the RCF and Term Loan. In the third quarter of 2017, the Company incurred total finance expense of $2.2 million, comprised of $0.2 million in non-cash accretion of its decommissioning obligation and $1.9 million cash interest expense.

The Company incurred total finance expense of $7.0 million for the nine month period ending September 30, 2018, compared to $6.2 million for the prior year comparative period. The increases in interest expense from 2017 to 2018 on both the three and nine month basis is due to increases in the underlying prime interest rate. These increases were offset by reductions in the Company's outstanding RCF.

DEPLETION AND DEPRECIATION

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

Depletion and Depreciation Expense ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Depletion and depreciation expense	**9,631**	15,029	**31,744**	39,960
Depletion and depreciation expense ($/boe)	**12.56**	15.46	**12.39**	14.56

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 third quarter of 2018 of $9.6 million or $12.56 per boe, compared to the third quarter of 2017, when $15.0 million or $15.46 per boe was recorded. For the nine month period ending September 30, 2018, the Company recorded $31.7 million or $12.39 per boe, compared to $40.0 million or $14.56 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Weighted average Common Shares outstanding				
Basic	**49,492**	49,428	**49,492**	48,098
Fully diluted	**49,492**	49,428	**49,492**	48,098
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	**3,071**	2,772	**3,071**	2,772
Performance warrants outstanding	**—**	86	**—**	86

At September 30, 2018, the Company had 49,491,840 Common Shares and 3,071,201 stock options outstanding.

The Company issued 1,058,400 stock options during the nine months ended September 30, 2018 as follows:

(a) 549,900 stock options were issued on May 28, 2018 at an exercise price of $1.49.
(b) 508,500 stock options were issued on August 17, 2018 at an exercise price of $0.86.

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. At September 30, 2018, 130,038 (December 31, 2017 – 130,038) deferred share units were issued and outstanding. Each DSU entitles the participants to receive, at the Company's discretion, either shares of the Company or cash equal to the trading price of the equivalent number of shares of the Company. All DSUs granted vest and become payable upon retirement of the director.

LIQUIDITY AND CAPITAL RESOURCES

At September 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 September 30, 2018, the RCF was comprised of a $20 million operating facility and a $90 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. The RCF syndicate of lenders completed their 2018 semi-annual review of the RCF and have maintained the Company's borrowing base at $110 million.

At September 30, 2018, the Company had a $0.7 million letter of credit outstanding against the RCF (December 31, 2017 – $0.3 million) and had drawn $96.3 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 September 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 September 30, 2018 interim consolidated financial statements. The Company was in compliance with all financial covenants at September 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 September 30, 2018, the Company had a working capital deficiency (excluding the risk management asset or liability) of $1.0 million. 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 May 31, 2019. 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 September 30, 2018:

$000s	Total	< 1 year	1-5 years
Accounts payable	12,145	12,145	—
Risk management liability	15,837	12,372	3,465
Long term debt[(1)]	131,300	—	131,300
Total	**159,282**	**24,517**	**134,765**

[(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	954	716	239	—
Firm service transportation	19,752	1,073	12,578	6,100
Total commitments	**20,706**	**1,789**	**12,817**	**6,100**

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 September 30, 2018 interim consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $3.6 million in the third quarter of 2018, compared to $13.1 million in the third quarter of the prior year. For the nine months ended September 30, 2018, Petrus invested $11.5 million compared to $49.8 million in the same period in 2017. 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 September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Drill and complete	**2,741**	7,672	**6,082**	33,946
Oil and gas equipment	**368**	4,872	**2,550**	13,905
Geological	**—**	225	**—**	225
Land and lease	**106**	22	**1,612**	—
Office	**—**	—	**—**	317
Capitalized general and administrative	**422**	264	**1,252**	1,448
Total capital expenditures	**3,637**	**13,055**	**11,496**	**49,841**
Gross (net) wells spud	**2 (1.0)**	**5 (3.7)**	**4 (1.6)**	**16 (11.8)**

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

Acquisitions and Dispositions ($000s)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Acquisitions	**—**	—	**—**	8,818
Dispositions	**(50)**	(4,866)	**(448)**	(4,866)
Total acquisitions and dispositions	**(50)**	**(4,866)**	**(448)**	**3,952**

Dispositions totaled $0.05 million in the three months ended September 30, 2018 (compared to the prior year when dispositions totaled $4.9 million). During the nine months ended September 30, 2018, Petrus divested non-core assets for approximately $0.4 million (net A&D activity in the prior year of $4.0 million).

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016
Average Production								
Natural gas (mcf/d)	33,461	39,126	45,543	46,625	45,550	42,392	40,332	37,327
Oil (bbl/d)	1,243	1,484	1,530	1,854	1,877	2,015	1,542	1,452
NGLs (bbl/d)	1,519	1,241	1,475	1,086	1,098	1,160	1,067	922
Total (boe/d)	**8,338**	**9,246**	**10,596**	**10,711**	**10,567**	**10,240**	**9,331**	**8,595**
Total (boe)	**767,095**	**841,316**	**953,598**	**985,388**	**972,140**	**931,821**	**839,746**	**790,806**
Financial Results								
Oil and natural gas revenue	20,030	19,321	25,301	23,243	18,299	26,753	22,274	21,409
Royalty expense	(2,391)	(2,137)	(4,674)	(3,000)	(2,656)	(4,306)	(3,309)	(2,787)
Net oil and natural gas revenue	**17,639**	**17,184**	**20,627**	**20,243**	**15,643**	**22,447**	**18,965**	**18,622**
Transportation expense	(749)	(988)	(1,197)	(1,233)	(1,255)	(1,235)	(1,157)	(1,187)
Operating expense	(3,800)	(3,841)	(4,160)	(4,744)	(5,271)	(5,155)	(3,780)	(2,867)
Operating netback	**13,090**	**12,355**	**15,270**	**14,266**	**9,117**	**16,057**	**14,028**	**14,568**
Realized gain (loss) on derivatives	(2,061)	(625)	298	1,210	1,829	212	482	783
Other income	69	103	—	—	—	—	—	—
General & administrative expense	(1,317)	(1,372)	(1,430)	(266)	(1,059)	(1,047)	(882)	(2,991)
Cash finance expense	(1,941)	(2,097)	(1,865)	(1,515)	(1,936)	(1,807)	(1,736)	(2,043)
Decommissioning expenditures	(155)	—	(168)	(611)	(224)	(957)	(160)	(508)
Corporate netback	**7,685**	**8,364**	**12,105**	**13,084**	**7,727**	**12,458**	**11,732**	**9,809**
Oil and natural gas revenue	**20,030**	**19,321**	**25,301**	**23,243**	**18,299**	**26,753**	**22,274**	**21,409**
Per share - basic	0.40	0.39	0.51	0.47	0.37	0.54	0.48	0.47
Per share - fully diluted	0.40	0.39	0.51	0.47	0.37	0.54	0.47	0.47
Net income (loss)	**(8,048)**	**(10,615)**	**(5,684)**	**(67,095)**	**(50,696)**	**(781)**	**7,311**	**(11,842)**
Per share - basic	(0.16)	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)
Per share - fully diluted	(0.16)	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16	(0.26)
Common shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,492	49,428	49,428	49,428	45,349
Fully diluted	49,492	49,492	49,492	49,492	49,428	49,428	52,664	45,349
Weighted avg. shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,456	49,428	49,428	46,754	45,349
Fully diluted	49,492	49,492	49,492	49,456	49,428	49,428	46,989	45,349
Total assets	322,335	330,359	343,161	353,445	409,078	465,794	460,095	439,967
Net debt	**(131,603)**	**(135,111)**	**(142,238)**	**(148,066)**	**(137,531)**	**(137,069)**	**(130,624)**	**(124,915)**

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and funds flow are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus' average quarterly production decreased from 8,595 boe/d in the fourth quarter of 2016 to 8,338 boe/d in the third quarter of 2018. The 3% production decrease is attributable to certain production volume in the Foothills area being shut-in due to uneconomic natural gas pricing, partially offset by incremental volume attributed to the Company's development program at Ferrier.

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 September 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 July 1, 2018 and ending on September 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 Sept. 30, 2018		Three months ended Sept. 30, 2017		Nine months ended Sept. 30, 2018		Nine months ended Sept. 30, 2017	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	20,030	26.11	18,299	18.83	64,652	25.23	67,326	24.54
Royalty expense	(2,391)	(3.12)	(2,656)	(2.73)	(9,202)	(3.59)	(10,270)	(3.74)
Net oil and natural gas revenue	**17,639**	**22.99**	**15,643**	**16.10**	**55,450**	**21.64**	**57,056**	**20.80**
Transportation expense	(749)	(0.98)	(1,255)	(1.29)	(2,934)	(1.15)	(3,647)	(1.33)
Operating expense	(3,800)	(4.95)	(5,271)	(5.42)	(11,801)	(4.61)	(14,206)	(5.18)
Operating netback	**13,090**	**17.06**	**9,117**	**9.39**	**40,715**	**15.88**	**39,203**	**14.29**
Realized gain (loss) on financial derivatives	(2,061)	(2.69)	1,829	1.88	(2,388)	(0.93)	2,523	0.92
Other income	69	0.08	—	—	172	0.10	—	—
General & administrative expense	(1,317)	(1.72)	(1,059)	(1.09)	(4,119)	(1.61)	(2,988)	(1.09)
Cash finance expense	(1,941)	(2.53)	(1,936)	(1.99)	(5,903)	(2.30)	(5,479)	(2.00)
Decommissioning expenditures	(155)	(0.20)	(224)	(0.23)	(323)	(0.13)	(1,341)	(0.48)
Corporate netback	**7,685**	**10.00**	**7,727**	**7.96**	**28,154**	**11.01**	**31,918**	**11.64**

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 September 30, 2018**	**As at December 31, 2017**
Current assets adjusted for unrealized financial instruments	**11,146**	13,042
Less: current liabilities adjusted for unrealized financial instruments	**(12,145)**	(29,201)
Less: long term debt	**(130,604)**	(131,907)
Net debt	**(131,603)**	**(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 and the timing for bringing wells on stream; expected year end 2018 net debt; 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

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