ANNUAL REPORT

December 31, 2018

2018 HIGHLIGHTS

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report financial and operating results for the three and twelve month periods ended December 31, 2018 and to provide 2018 year end reserves information as evaluated by Sproule Associates Limited ("Sproule"). The Company's Management's Discussion and Analysis ("MD&A") and audited consolidated financial statements dated as at and for the year ended December 31, 2018 are available on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

In 2018, the Company's primary objectives were to improve its financial position and to increase its light oil weighting. This was done in order to increase the value of its production and funds flow per share. The Company's Ferrier Cardium asset base provides optionality between natural gas and light oil which allows the Company's development program to respond to changes in commodity pricing. The Company planned to invest $25 to $30 million in 2018, directed toward drilling Cardium light oil wells in Ferrier and targeted debt reduction of $10 to $15 million. Petrus substantially achieved these objectives in 2018: $24.1 million was invested in 2018 to drill 10 gross (4.3 net) Cardium light oil wells in Ferrier, each with a significantly higher number of multi-stage fracs than had been used in the past. The Company's December 2018 light oil weighting increased 59% from January 2018 and the full impact of the higher liquids weighting is expected to be represented in 2019(2). The Company ended 2018 with net debt(1) of $139.2 million, which is an $8.9 million or 6% decrease since December 31, 2017(1).

- **Light oil development** - In 2018 Petrus set out to prove its Cardium light oil inventory and maximize its return on investment by significantly increasing the number of fracture stimulations used in its completion operations. Petrus drilled or participated in 2 gross (0.7 net) Cardium condensate wells during the first half of 2018. Petrus strategically deferred further capital development until the second half of 2018 in order to permit debt repayment early in the year as well as to provide time to analyze well performance to evaluate the new completion techniques. The Company's 2018 operated drilling program resumed in the second half of 2018 with 5 gross (2.9 net) Cardium light oil wells drilled and fracture stimulated with an average of 76 stages per one mile lateral length. The December test production, over a 14 day period, attributed to Petrus' 2.9 net additional wells was approximately 2,000 boe/d(3), which was comprised of 50% light oil (60% total liquids). The light oil test rates of approximately 1,000 boe/d nearly doubled Petrus' light oil production reported for the third quarter of 2018 of 1,243 boe/d. Petrus is pleased with the results of the 2018 drilling program and looks forward to continued development of its Cardium light oil in Ferrier in a consistent, disciplined manner. The Company plans to drill throughout 2019 within funds flow and repay $1 to $2 million of debt each quarter. Petrus' Board of Directors has approved a second quarter 2019 capital budget of $7 to $8 million, based on a current forecast for commodity futures pricing, anticipated service costs and current activity levels.

- **Increased liquids weighting** - Fourth quarter average production was 7,934 boe/d in 2018 compared to 10,711 boe/d in 2017. The new liquids production related to the fourth quarter 2018 wells is not reflected for a full quarter as the wells were brought on stream in December. The new production is more valuable in the current commodity environment as the light oil and total liquids weighting have increased significantly. The Company's December 2018 light oil weighting increased 59% from January 2018. Similarly, the Company's December 2018 total liquids weighting was 40% which is a 43% increase from January 2018. The Company's operating netback increased 5% from $14.33 per boe(3) in 2017 to $15.08 per boe in 2018; however the full impact of the increase in liquids weighting is not reflected due to when the new wells were brought on-stream, in late December.

- **Company best F&D costs** - In 2018, the Company realized Finding and Development ("F&D") costs of $5.15/boe and $8.16/boe for Proved Plus Probable ("P+P") and Total Proved ("TP"), respectively. These finding costs were the best in the Company's history. In terms of deploying capital to create reserves volume and value, this was the most effective year Petrus has ever had.

- **Reserve value growth** - Petrus ended 2018 with $316 million and $507 million of Total Proved ("TP") and Proved Plus Probable ("P+P"), respectively, reserve values before-tax, discounted at 10%. The reserve values increased by 1% and 5%, respectively, from the December 31, 2017 Sproule Report. Absent of any changes to the December 31, 2017 Sproule Price forecast, the reserve values would have increased by 22% and 24%, respectively. In 2018, Petrus was also able to increase its Reserve Life Index in every reserve category.

- **Best in class operating costs** - Total operating expenses were 6% lower from 2017 at $4.75 per boe in 2018 which is the lowest operating cost in the Company's history (a 57% decrease since 2012) and marks the third consecutive year of operating cost reductions. The Company continues to focus on optimizing its cost structure, particularly in the Ferrier area, through facility ownership and control.

- **Funds flow** - Petrus generated funds flow of $5.0 million in the fourth quarter of 2018 which is lower than the $13.1 million generated in the fourth quarter of 2017 primarily due to significantly lower market price of Edmonton light oil and natural gas (AECO) during the fourth quarter of 2018. Relative to global oil prices (West Texas Intermediate), Western Canadian light oil traded at historically high differentials in the fourth quarter mainly due to insufficient take away capacity. On December 2, 2018 the Alberta government announced a production curtailment mandate of 325,000 boe/d of Alberta crude oil production effective January 1, 2019. In February, the Alberta government announced plans to transport 120,000 boe/d via rail by 2020. These measures were intended to help alleviate current take away capacity constraints impacting Alberta producers and to reduce storage levels. The temporary production reduction applies to all operators in Alberta producing in excess of 10,000 barrels per day of oil production. Petrus' oil production is within the 10,000 barrels per day and therefore the Company is exempt from reducing production. As a result of these measures, the differential for Western Canadian light oil prices has tightened significantly.

- **Commodity price risk mitigation** - Petrus 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. During the fourth quarter, the Company recognized a $1.3 million ($1.38 per boe) realized gain related to natural gas, offset by a $1.9 million ($2.61 per boe) realized loss related to light oil. As a percentage of fourth quarter 2018 production, Petrus has derivative contracts in place for 52%, at an average price of $2.00/mcf and 53% at an average price of $68.79/bbl, of its natural gas and oil and natural gas liquids production, respectively, for 2019.

(1) Refer to "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.
(2) Refer to "Advisories - Forward-Looking Statements" in the Management's Discussion & Analysis attached hereto.
(3) Refer to "Advisories - BOE Presentation" in the Management's Discussion & Analysis attached hereto.

PRESIDENT'S MESSAGE

In 2018 Petrus set out to accomplish two main goals: improve our balance sheet, and execute a focused capital program concentrated on Cardium light oil to raise the Company's liquids weighting.

By year end we spent $24 million on capital development and reduced our net debt by $9 million or 6%. Since 2015, we have made significant progress in improving our balance sheet by reducing our net debt by $88 million or 39%. Balance sheet strength remains one of our top priorities. This attention to leverage improvement continues with our plans for 2019 where we look to further repay our net debt by $1 to $2 million each quarter.

Petrus was also able to make significant headway on increasing our liquids production. Through the high quality inventory of Cardium light oil locations we have in Ferrier, in 2018 we were able to increase our oil weighting by 59% and bring our total liquids weighting to 40%. We continue to advance our drilling and completion techniques and in 2019 we are targeting to raise our liquids weighting again through further Cardium oil development in Ferrier.

Challenged commodity prices and heightened volatility continued to be major themes in 2018 for the Canadian energy market. Partially offsetting this volatility, Petrus' production has a number of attributes that successfully aid us in mitigating these challenges. Our reported oil production is primarily a lighter grade condensate which received a $9/bbl premium to Western Canadian light oil pricing for the year. Similarly, our natural gas production has a higher than average energy content resulting in a $0.40/mcf premium to AECO pricing. The Company also has an active hedging program with approximately 65% of our oil and natural gas production hedged during the fourth quarter of 2018. Those hedges helped insulate us from falling prices and will continue to provide price protection through the contracts we have in place for approximately half of our 2019 volumes.

We achieved a variety of other operational successes as highlighted by our 2018 reserve and annual report. Our Cardium oil drilling program was the most efficient in the Company's history in terms of rate of return and payout. Our F&D costs were also the lowest in the Company's history at $5.15/boe and $8.16/boe for Total Proved plus Probable and Total Proved, respectively. The value of both our Total Proved and Total Proved plus Probable reserves increased year over year despite a decrease in our reserve evaluator's price forecast. Had the price forecast remained constant, the Company would have seen a 24% increase in our Total Proved plus Probable value. And similar to previous years, while many operational aspects of Petrus were growing, our operating expenses continued to decline for the third consecutive year and were $4.75/boe for 2018, the Company's lowest ever.

By many metrics Petrus had an exceptional year in 2018, and we're excited about our future. Cardium light oil drilling in Ferrier has been proven over recent years and we look to further develop this repeatable asset in 2019. Based on the current commodity price environment, our Cardium light oil locations are offering payouts of less than 10 months, which will again, help the Company further strengthen our balance sheet and improve our liquids weighting. It continues to be a challenging time for the Canadian energy market, however with a disciplined approach we continue to make our business stronger and more resilient.

Neil Korchinski
President, Chief Executive Officer and Director

RESERVES

Petrus' 2018 year end reserves were evaluated by independent reserves evaluator Sproule Associates Limited ("Sproule") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2018 ("2018 Sproule Report"). Additional reserve information as required under NI 51-101 will be included in our Annual Information Form for the year ended December 31, 2018, which will be filed on SEDAR.

Petrus has a reserves committee, comprised of independent board members, that reviews the qualifications and appointment of the independent reserve evaluators. The committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the independent qualified reserve evaluators conducted in accordance with the COGE Handbook and NI 51-101. The evaluations are conducted using all available geological and engineering data. The reserves committee has reviewed the reserves information and approved the 2018 Sproule Report.

The following table provides a summary of the Company's before tax reserves as evaluated by Sproule:

As at December 31, 2018	Total Company Interest [1][3]						
Reserve Category	**Conventional Natural Gas (mmcf)**	**Light and Medium Crude Oil (mbbl)**	**NGL (mbbl)**	**Total (mboe)**	**NPV 0%[2] ($000s)**	**NPV 5%[2] ($000s)**	**NPV 10%[2] ($000s)**
Proved Producing	52,491	1,250	3,388	13,386	258,437	211,579	181,588
Proved Non-Producing	16,980	94	121	3,044	21,959	16,299	12,754
Proved Undeveloped	57,180	1,474	4,882	15,887	249,274	172,272	121,860
Total Proved	**126,650**	**2,818**	**8,391**	**32,317**	**529,671**	**400,149**	**316,203**
Proved + Probable Producing	67,773	1,672	4,255	17,223	348,210	264,084	216,812
Total Probable	**65,072**	**2,519**	**4,320**	**17,684**	**390,858**	**262,581**	**190,929**
Total Proved Plus Probable	**191,723**	**5,337**	**12,710**	**50,001**	**920,528**	**662,730**	**507,132**

[1] Tables may not add due to rounding.
[2] NPV 0%, NPV 5% and NPV 10% refer to the risked net present value of the future net revenue of the Company's reserves, discounted by Nil, 5% and 10%, respectively and is presented before tax and based on Sproule's pricing assumptions.
[3] Total company interest reserve volumes are presented above and in the remainder of this annual report are presented as the Company's total working interest before the deduction of royalties (but after including any royalty interests of Petrus).

In 2018, Petrus' development program generated Proved Developed Producing ("PDP") reserve volume additions of 0.6 mmboe which were comprised of 100% liquids. The Company produced 3.3 mmboe during 2018 and ended the year with 13.4 mmboe of PDP reserve volume. Petrus' PDP liquids percentage increased from 28% in 2017 to 35% in 2018.

Petrus ended 2018 with $194.3 million, $316.2 million and $507.1 million of Proved Developed ("PD"), Total Proved ("TP"), and Proved plus Probable ("P+P"), respectively, reserve value before-tax, discounted at 10%, based on the 2018 Sproule Report. In 2018, the Company realized Finding and Development ("F&D") costs[3] of $11.55/boe, $8.16/boe and $5.15/boe for PD, TP and P+P reserves, respectively. PDP F&D costs were materially influenced by the shut in of uneconomic dry gas volumes in the Foothills; therefore, PD is a more indicative metric for developed finding costs in 2018.

Based on the 2018 Sproule Report, the Company's PDP reserve value before-tax, discounted at 10% is $ 3.67 per share. On the same basis, the P+P reserve value is $10.25 per share.

FUTURE DEVELOPMENT COST

Future Development Cost ("FDC") reflects Sproule's best estimate of what it will cost to bring the P+P undeveloped reserves on production. FDC associated with Petrus' total P+P reserves at December 31, 2018, based on the 2018 Sproule Report, is $290.9 million (undiscounted) and includes 230 gross (128.2 net) booked P+P locations.

The following table provides a summary of the Company's FDC as set forth in the 2018 Sproule Report:

Future Development Cost ($000s)	Total Proved	Total Proved + Probable
2018	67,578	81,596
2019	79,748	147,315
2020	45,822	60,356
2021	1,609	1,609
Thereafter	—	—
Total FDC, Undiscounted	**194,757**	**290,876**
Total FDC, Discounted at 10%	**172,129**	**255,422**

PERFORMANCE RATIOS
The following table highlights annual performance ratios for the Company from 2014 to 2018:

	December 31, 2018	December 31, 2017	December 31, 2016	December 31, 2015	December 31, 2014
Proved Producing					
FD&A ($/boe) (1)(2)	**37.76**	13.05	(0.43)	23.18	35.35
F&D ($/boe) (1)(2)	**42.27**	11.57	9.89	29.80	59.67
Reserve Life Index (yr) (1)	**4.6**	4.1	4.4	5.2	4.6
Reserve Replacement Ratio (1)	**0.2**	1.6	0.4	0.7	5.9
FD&A Recycle Ratio (1)	**0.4**	1.1	(24.8)	0.7	0.8
Proved Developed					
FD&A ($/boe) (1)(2)	**11.34**	16.74	(0.23)	39.85	32.06
F&D ($/boe) (1)(2)	**11.55**	14.62	7.69	65.74	68.87
Reserve Life Index (yr) (1)	**5.6**	4.5	5.3	5.8	5.4
Reserve Replacement Ratio (1)	**0.6**	1.2	0.7	0.4	6.5
FD&A Recycle Ratio (1)	**1.4**	0.9	(46.3)	0.4	0.9
Total Proved					
FD&A ($/boe) (1)(2)	**8.73**	14.33	(15.78)	16.77	27.82
F&D ($/boe) (1)(2)	**8.16**	12.03	2.46	21.02	122.89
Reserve Life Index (yr) (1)	**11.1**	8.0	9.8	10.9	7.3
Reserve Replacement Ratio (1)	**1.3**	1.1	0.5	2.9	9.1
FD&A Recycle Ratio (1)	**1.8**	1.0	(0.7)	0.9	1.0
Future Development Cost ($000s)	**194,757**	182,086	201,556	223,409	122,326
Total Proved + Probable					
FD&A ($/boe) (1)(2)	**6.49**	14.87	350.09	15.40	21.49
F&D ($/boe) (1)(2)	**5.15**	17.28	(8.06)	19.01	(604.56
Reserve Life Index (yr) (1)	**17.1**	12.3	14.6	16.4	11.2
Reserve Replacement Ratio (1)	**1.5**	1.7	(0.1)	3.7	12.7
FD&A Recycle Ratio (1)	**2.4**	1.0	—	1.0	1.3
Future Development Cost ($000s)	**290,876**	283,030	269,144	325,325	199,410

(1)Refer to "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto.
(2)Certain changes in FD&A and F&D produce non-meaningful figures as discussed in "Oil and Gas Disclosures" in the Management's Discussion & Analysis attached hereto. While FD&A and F&D costs, reserve life index, reserve replacement ratio and finding and development costs are commonly used in the oil and nature gas industry and have been prepared by management, these terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons.
FD&A and F&D costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total FD&A and F&D costs related to reserves additions for that year.

NET ASSET VALUE

The following table shows the Company's Net Asset Value ("NAV"), calculated using the price forecast from Sproule:

As at December 31, 2018 ($000s except per share)	Proved Developed Producing	Total Proved	Proved + Probable
Present Value Reserves, before tax (discounted at 10%) [(1)]	181,588	316,203	507,132
Undeveloped Land Value [(2)]	42,410	42,410	42,410
Net Debt [(3)]	(139,214)	(139,214)	(139,214)
Net Asset Value	84,784	219,399	410,328
Fully Diluted Shares Outstanding [(4)]	49,492	49,492	49,492
Estimated Net Asset Value per Share	**$1.71**	**$4.43**	**$8.29**

[(1)]Based on the 2018 Sproule Report, using the forecast future prices and costs.

[(2)]Based on the exploration and evaluation assets as per the Company's December 31, 2018 audited consolidated financial statements.

[(3)]See "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.

[(4)]There were no "in-the-money" options or warrants based on the Company's December 31, 2018 closing share price of $0.52, therefore the calculation uses the common shares outstanding at December 31, 2018.

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 year ended December 31, 2018. The MD&A is dated March 13, 2019 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2018 and 2017. 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" section at the end of this MD&A 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	Twelve months ended Dec. 31, 2018	Twelve months ended Dec. 31, 2017	Three months ended Dec. 31, 2018	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018
Average Production						
Natural gas (mcf/d)	37,101	43,747	30,480	33,461	39,126	45,543
Oil (bbl/d)	1,402	1,823	1,358	1,243	1,484	1,530
NGLs (bbl/d)	1,433	1,103	1,496	1,519	1,241	1,475
Total (boe/d)	**9,019**	**10,217**	**7,934**	**8,338**	**9,246**	**10,596**
Total (boe)	**3,292,828**	**3,729,095**	**730,819**	**767,095**	**841,316**	**953,598**
Natural gas sales weighting	69%	71%	64%	67%	71%	72%
Realized Prices						
Natural gas ($/mcf)	1.73	2.39	1.95	1.50	1.24	2.18
Oil ($/bbl)	69.74	59.56	52.26	77.24	75.29	73.91
NGLs ($/bbl)	40.50	31.52	29.01	45.27	41.53	46.50
Total realized price ($/boe)	**24.40**	**24.26**	**21.91**	**25.79**	**22.92**	**26.50**
Royalty income	0.12	0.02	0.10	0.32	0.05	0.03
Royalty expense	(3.54)	(3.56)	(3.34)	(3.12)	(2.54)	(4.90)
Net oil and natural gas revenue ($/boe)	**20.98**	**20.72**	**18.67**	**22.99**	**20.43**	**21.63**
Operating expense	(4.75)	(5.08)	(5.28)	(4.95)	(4.57)	(4.36)
Transportation expense	(1.15)	(1.31)	(1.17)	(0.98)	(1.17)	(1.26)
Operating netback [(1)] ($/boe)	**15.08**	**14.33**	**12.22**	**17.06**	**14.69**	**16.01**
Realized gain (loss) on derivatives ($/boe)	(0.90)	1.00	(0.79)	(2.69)	(0.74)	0.31
Other income	0.13	—	0.37	0.08	0.12	—
General & administrative expense	(1.57)	(0.87)	(1.46)	(1.72)	(1.63)	(1.50)
Cash finance expense	(2.51)	(1.88)	(3.25)	(2.53)	(2.49)	(1.96)
Decommissioning expenditures	(0.14)	(0.52)	(0.21)	(0.20)	—	(0.23)
Funds flow and corporate netback [(1)] ($/boe)	**10.09**	**12.06**	**6.88**	**10.00**	**9.95**	**12.63**

FINANCIAL (000s except per share)	Twelve months ended Dec. 31, 2018	Twelve months ended Dec. 31, 2017	Three months ended Dec. 31, 2018	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018
Oil and natural gas revenue	80,716	90,569	16,064	20,030	19,321	25,301
Net income (loss)	(3,284)	(111,261)	21,063	(8,048)	(10,615)	(5,684)
Net income (loss) per share						
Basic	(0.07)	(2.28)	0.43	(0.16)	(0.21)	(0.11)
Fully diluted	(0.07)	(2.28)	0.43	(0.16)	(0.21)	(0.11)
Funds flow	33,184	45,003	5,030	7,685	8,364	12,105
Funds flow per share						
Basic	0.67	0.92	0.10	0.16	0.17	0.24
Fully diluted	0.67	0.92	0.10	0.16	0.17	0.24
Capital expenditures	24,098	72,750	12,660	3,637	1,745	6,056
Net acquisitions (dispositions)	(448)	4,741	(6)	(50)	(269)	(123)
Weighted average shares outstanding						
Basic	49,492	48,825	49,492	49,492	49,492	49,492
Fully diluted	49,492	48,825	49,492	49,492	49,492	49,492
As at period end						
Common shares outstanding						
Basic	49,492	49,492	49,492	49,492	49,492	49,492
Fully diluted	49,492	49,492	49,492	49,492	49,492	49,492
Total assets	341,820	353,445	341,820	322,335	330,359	343,161
Non-current liabilities	171,646	173,272	171,646	170,908	172,757	174,634
Net debt [(1)]	139,214	148,066	139,214	131,603	135,111	142,238

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

[(2)]Corporate netback is equal to funds flow which is a directly comparable GAAP measure. Petrus analyzes these measures on an absolute value and per unit basis.

OPERATIONS UPDATE

Production

Fourth quarter average production by area was as follows:

For the three months ended December 31, 2018	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	22,254	1,998	6,228	30,480
Oil (bbl/d)	812	160	386	1,358
NGLs (bbl/d)	1,317	5	174	1,496
Total (boe/d)	**5,837**	**499**	**1,598**	**7,934**
Natural gas sales weighting	***58%***	***66%***	***65%***	***64%***

Petrus set out in 2018 to prove its Cardium light oil inventory and maximize its return on investment by significantly increasing the number of fracture stimulations used in its completion operations. Petrus drilled or participated in 2 gross (0.7 net) Cardium condensate wells during the first half of 2018. Petrus strategically deferred further capital development until the second half of 2018 in order to permit debt repayment early in the year as well as to provide time to analyze well performance to evaluate the new completion techniques. The Company's 2018 operated drilling program resumed in the second half of 2018 with 5 gross (2.9 net) Cardium light oil wells drilled and fracture stimulated with an average of 76 stages per one mile lateral length. The December test production, over a 14 day period, attributed to Petrus' 2.9 net additional wells was approximately 2,000 boe/d, which was comprised of 50% light oil (60% total liquids). The light oil test rates of approximately 1,000 boe/d nearly doubled Petrus' light oil production reported for the third quarter of 2018 of 1,243 boe/d. Petrus is pleased with the results of the 2018 drilling program and looks forward to continue development of its Cardium light oil in Ferrier in a consistent, disciplined manner. The Company plans to drill evenly throughout 2019 within funds flow and repay $1 to $2 million of debt each quarter.

Fourth quarter average production was 7,934 boe/d in 2018 compared to 10,711 boe/d in 2017. Looking at the Company's recent change in total boe production rates is inaccurate as an evaluation of potential cash flow and value. In the current commodity price environment, as liquids weighting increases, cash flow and value can increase despite lower overall boe production. The new liquids production related to the fourth quarter 2018 wells is not reflected for a full quarter as the wells were brought on-stream in December. The resulting production is more valuable in the current commodity environment as the light oil and total liquids weighting has increased significantly. The Company's December 2018 light oil weighting increased 59% from January 2018. Similarly, the Company's December 2018 total liquids weighting was 40% which is a 43% increase from January 2018. The Company's operating netback increased 5% from $14.33 per boe in 2017 to $15.08 per boe in 2018; however the full impact of the increase in liquids weighting is not reflected due to when the new wells were brought on stream, in late December.

In 2018, the Company's drilling program proved that the Ferrier Cardium asset base provides optionality between natural gas or light oil development. This optionality permits the Company's development program to be agile and efficiently respond to changes in commodity pricing.

Petrus' Board of Directors has approved a first quarter 2019 capital budget of $8 to $10 million, based on a current forecast for commodity futures pricing, anticipated service costs and current activity levels. Management anticipates that the 2019 capital plan will be fully funded by funds flow, systematically scheduled evenly through the year to maintain flexibility, and permit debt reduction each quarter. In the first quarter of 2019 the Company expects to generate funds flow between $10 and $11 million, with the remaining $1 to $2 million to be directed toward debt repayment. The commodity price assumptions used for the first quarter 2019 capital budget were an average price of $1.31 C$/GJ for natural gas (AECO) and $53.03 US$/bbl for oil (WTI). Petrus' estimated first quarter average differential for Western Canadian light oil is estimated at $7.55 US$/bbl. The first quarter capital budget is expected to include the drilling of 5 gross (2.0 net) Cardium wells targeting the most condensate rich areas within the reservoir.

As part of the 2019 first quarter capital budget, Petrus has drilled 2 gross (1.2 net) Cardium light oil wells. The wells have finished drilling and offset the recently drilled 5 gross (2.9 net) wells from the fourth quarter 2018 drilling program. The 2 first quarter 2019 wells have 1.5 mile and 1.0 mile horizontal lateral lengths, respectively. Both wells are being fracture stimulated with 124 and 77 stages, respectively. Completion operations are currently ongoing and the wells' test volumes can flow inline as the wells were drilled from pre-existing surface locations. Both wells are expected to be on production by the end of March.

Petrus' Board of Directors has approved a second quarter 2019 capital budget of $7 to $8 million, based on a current forecast for commodity futures pricing, anticipated service costs and current activity levels. The second quarter budget will allow for debt repayment of $1 to $2 million in the quarter.

Petrus estimates the 2019 capital plan will maintain production year over year, increase its oil and total liquids weighting, and reduce debt throughout the year. Approximately 85% of the capital plan will be directed to development of Cardium light oil wells in the Ferrier area of Alberta, which we estimate will have payouts of less than one year and achieve its objective to increase its light oil production weighting and funds flow.

[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

	Twelve months ended Dec. 31, 2018	Twelve months ended Dec. 31, 2017	Three months ended Dec. 31, 2018	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018
Average production						
Natural gas (mcf/d)	37,101	43,747	30,480	33,461	39,126	45,543
Oil (bbl/d)	1,402	1,823	1,358	1,243	1,484	1,530
NGLs (bbl/d)	1,433	1,103	1,496	1,519	1,241	1,475
Total (boe/d)	**9,019**	**10,217**	**7,934**	**8,338**	**9,246**	**10,596**
Total (boe)	**3,292,828**	**3,729,095**	**730,819**	**767,095**	**841,316**	**953,598**
Revenue ($000s)						
Natural Gas	23,453	38,156	5,473	4,630	4,432	8,918
Oil	35,684	39,633	6,522	8,828	10,159	10,175
NGLs	21,186	12,685	3,993	6,326	4,692	6,175
Royalty revenue	393	95	76	246	38	33
Oil and natural gas revenue	**80,716**	**90,569**	**16,064**	**20,030**	**19,321**	**25,301**
Average realized prices						
Natural gas ($/mcf)	1.73	2.39	1.95	1.50	1.24	2.18
Oil ($/bbl)	69.74	59.56	52.26	77.24	75.29	73.91
NGLs ($/bbl)	40.50	31.52	29.01	45.27	41.53	46.50
Total realized price ($/boe)	24.40	24.26	21.91	25.79	22.92	26.50
Hedging gain (loss) ($/boe)	(0.90)	1.00	(0.79)	(2.69)	(0.74)	0.31
Total price including hedging ($/boe)	**23.50**	**25.26**	**21.12**	**23.10**	**22.18**	**26.81**

Average benchmark prices	Twelve months ended Dec. 31, 2018	Twelve months ended Dec. 31, 2017	Three months ended Dec. 31, 2018	Three months ended Sept. 30, 2018	Three months ended Jun. 30, 2018	Three months ended Mar. 31, 2018
Natural gas						
AECO 5A ($/GJ)	1.42	2.04	1.47	1.13	1.12	1.97
AECO 7A ($/GJ)	1.45	2.30	1.80	1.28	0.97	1.76
Crude Oil						
Mixed Sweet Blend Edm ($/bbl)	69.13	62.28	48.12	79.65	78.91	72.28
Foreign Exchange						
US$/C$	0.77	0.77	0.76	0.77	0.78	0.80

FUNDS FLOW AND NET INCOME (LOSS)

Petrus generated funds flow of $5.0 million in the fourth quarter of 2018, a decrease relative to the $13.1 million generated in the fourth quarter of 2017. The decrease is due to 26% lower production, a 28% decrease in light oil pricing (Edm CAD$) and 8% lower natural gas pricing (AECO 5A). On a twelve month basis, funds flow was 26% lower at $33.2 million in 2018 compared to $45.0 million in the prior year. The decrease is due to 30% lower natural gas pricing (AECO 5A) and 12% lower production, partially offset by 11% higher light oil pricing (Edm CAD $).

Petrus reported net income of $21.1 million in the fourth quarter of 2018, compared to a net loss of $67.1 million in the fourth quarter of 2017. The net income in the fourth quarter of 2018 opposed to the net loss in the prior year is primarily due to the accounting for the unrealized hedging on financial derivatives, as well as the recognition of an impairment loss in the fourth quarter of 2017. The accounting for the unrealized hedging on financial derivatives had a material impact on earnings; during the fourth quarter of 2017, the Company recognized an unrealized loss of $1.3 million whereas during the fourth quarter of 2018 a $24.8 million unrealized gain was recorded. The differences are due to changes in commodity prices at December 31 of the respective years. On a twelve month basis, the Company generated 97% lower net loss of $3.3 million in 2018 compared to $111.3 million in 2017. The decrease in net loss is mainly due to the impairment loss of $109 million recorded in 2017.

($000s except per share)	**Three months ended December 31, 2018**	**Three months ended December 31, 2017**	**Twelve months ended December 31, 2018**	**Twelve months ended December 31, 2017**
Funds flow	**5,030**	**13,084**	**33,184**	**45,003**
Funds flow per share - basic	0.10	0.26	0.67	0.92
Funds flow per share - fully diluted	0.10	0.26	0.67	0.92
Net income (loss)	**21,063**	**(67,093**	**(3,284)**	**(111,261)**
Net income (loss) per share - basic	0.43	(1.36	(0.07)	(2.28)
Net income (loss) per share - fully diluted	0.43	(1.36	(0.07)	(2.28)
Common shares outstanding (000s)				
Basic	49,492	49,492	49,492	49,492
Fully diluted	49,492	49,492	49,492	49,492
Weighted average shares outstanding (000s)				
Basic	49,492	49,456	49,492	48,825
Fully diluted	49,492	49,456	49,492	48,825

OIL AND NATURAL GAS REVENUE

Average production for the fourth quarter of 2018 was 7,934 boe/d (64% natural gas), 26% lower than the 10,711 boe/d (73% natural gas) average production for the fourth quarter of the prior year. The 26% 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. Total oil and natural gas revenue for the fourth quarter of 2018 was $16.1 million compared to $23.2 million in the fourth quarter of 2017. The 31% decrease is due to lower realized oil and natural gas liquids prices and lower production.

Average production for the year ended December 31, 2018 was 9,019 boe/d (69% natural gas), compared to 10,217 boe/d (71% natural gas) for the prior year. Total oil and natural gas revenue decreased from $90.6 million for the year ended December 31, 2017 to $80.7 million for the year ended December 31, 2018 mainly due to 12% lower production and 30% lower natural gas pricing (AECO 5A monthly index).

Natural gas

During the three and twelve months ended December 31, 2018, the average benchmark natural gas price in Canada (AECO 5A monthly index) decreased by 8% and 30%, respectively, from the prior year comparative periods (average price of $1.55 per mcf in the fourth quarter of 2018 compared to $1.69 per mcf in the fourth quarter of the prior year, and $1.50 per mcf for the year ended December 31, 2018, compared to $2.15 per mcf for the prior year comparative period).

The Company's average realized natural gas price during the fourth quarter of 2018 was $1.95 per mcf, compared to $1.90 per mcf in the fourth quarter of 2017, which represents a 3% increase. Natural gas revenue for the fourth quarter of 2018 was $5.5 million and production of 2,804,167 mcf accounted for approximately 64% of fourth quarter production volume and 34% of oil and natural gas revenue, compared to revenue of $8.1 million and production of 4,289,475 mcf accounting for approximately 73% of fourth quarter production volume and 35% 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 fourth quarter of 2018.

Natural gas revenue for the year ended December 31, 2018 was $23.5 million and production of 13,541,961 mcf accounted for approximately 69% of production volume and 29% of oil and natural gas revenue, compared to revenue of $38.2 million and production of 15,967,547 mcf for 72% of production volume and 42% of oil and natural gas revenue in the prior year. The decrease is due to lower natural gas prices and production.

Crude oil and condensate

Edmonton Light Sweet crude oil prices decreased 28% from the fourth quarter of 2017 to the fourth quarter of 2018 (an average price of $48.12 per bbl for the fourth quarter of 2018 compared to an average price of $66.93 per bbl for the prior year comparative period). Prices increased 11% from the year ended December 31, 2017 to the year ended December 31, 2018 ($69.13 per bbl in 2018 compared to an average of $62.28 per bbl in 2017).

The average realized price of Petrus' crude oil and condensate was $52.26 per bbl for the fourth quarter of 2018 compared to $66.10 per bbl for the same period in the prior year.

Oil and condensate revenue for the fourth quarter of 2018 was $6.5 million and production of 124,809 bbl accounted for approximately 17% of total production volume and 41% of oil and natural gas revenue, compared to revenue of $11.3 million and production of 170,563 bbl accounting for approximately 17% of total production volume and 49% of oil and natural gas revenue in the fourth quarter of the prior year.

Oil and condensaterevenue for the year ended December 31, 2018 was $35.7 million and production of 511,698 bbl accounted for approximately 15% of total production volume and 44% of oil and natural gas revenue, compared to revenue of $39.6 million and production of 665,390 bbl for 18% of total production volume and 44% of oil and natural gas revenue for the year ended December 31, 2017.

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 fourth quarter of 2018, the overall realized NGL price averaged $29.01 per bbl, compared to $38.00 per bbl in the prior year. The decrease is attributed to lower commodity prices as well as a change in the composition of the Company's NGLs.

NGL revenue for the fourth quarter of 2018 was $4.0 million and production of 137,649 bbl accounted for approximately 19% of production volume and 25% of oil and natural gas revenue, compared to revenue of $3.8 million and production of 99,912 bbl accounted for approximately 10% of production volume and 16% of oil and natural gas revenue for the fourth quarter of the prior year.

NGL revenue for the year ended December 31, 2018 was $21.2 million and production of 523,136 bbl accounted for approximately 16% of production volume and 26% of oil and natural gas revenue in the period, compared to revenue of $12.7 million and production of 402,446 bbl for 11% of production volume and 14% of oil and natural gas revenue for the year ended December 31, 2017.

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 December 31, 2018**	**Three months ended December 31, 2017**	**Twelve months ended December 31, 2018**	**Twelve months ended December 31, 2017**
Crown	**1,086**	1,038	**4,279**	5,353
Percent of production revenue	**7%**	4%	**5%**	6%
Gross overriding	**1,350**	1,962	**7,359**	7,917
Total	**2,436**	**3,000**	**11,638**	**13,270**

Total royalty expense (net of royalty allowances and incentives) decreased from $3.0 million in the fourth quarter of 2017 to $2.4 million in the fourth quarter of 2018 primarily due to 26% lower production and lower commodity pricing.

On a twelve month basis, total royalty expense (net of royalty allowances and incentives) decreased from $13.3 million in 2017 to $11.6 million in 2018. The decrease is also due to lower production and commodity pricing compared to the prior year.

Gross overriding royalties decreased from $2.0 million in the fourth quarter of 2017 to $1.4 million in the fourth quarter of 2018, due to lower natural gas prices. Gross overriding royalties were $7.4 million for the twelve months ended December 31, 2018, compared to $7.9 million in 2017. The reduction in the current year is also attributed to lower commodity pricing.

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 December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Realized hedging gain (loss)	**(573)**	1,210	**(2,961)**	3,732
Unrealized hedging gain (loss)	**25,370**	(2,518)	**7,510**	9,621
Net gain (loss) on derivatives	**24,797**	**(1,308)**	**4,549**	**13,353**

The Company recognized a realized hedging loss of $0.6 million during the fourth quarter of 2018, compared to a $1.2 million gain realized in the fourth quarter of the prior year. The realized loss in the current period is due to higher light oil prices (WTI CAD/bbl) offset by lower natural gas prices (relative to the respective contracts outstanding). The realized loss in the fourth quarter of 2018 decreased the Company's total realized price by $0.79 per boe, compared to the realized gain in the fourth quarter of the prior year, which increased the Company's total realized price by $1.23 per boe.

The Company recognized a realized hedging loss of $3.0 million during the twelve months ended December 31, 2018, compared to a $3.7 million gain realized in the prior year. The realized loss in the current year is due to strengthened annual average crude oil prices (WTI CAD/bbl) whereas in the prior year the gain was due to lower oil and natural gas prices.

The unrealized hedging gain of $25.4 million for the three months ended December 31, 2018 represents the change in the unrealized net risk management position during the quarter. The unrealized hedging gain of $7.5 million for the twelve months ended December 31, 2018 represents the change in the unrealized net risk management position during 2018. These changes are 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.

There was a significant change in the Company's net risk management position between the third and fourth quarter of 2018 as a result of volatility in the quarter ending oil price which is used to calculate the risk management asset or liability mark-to-market value. The WTI price decreased by 38%, from $73.25 USD/bbl as at September 30, 2018 to $45.41 USD/bbl as at December 31, 2018. On September 30, 2018, the unrealized risk management net mark-to-market value was a $15.8 million liability compared to December 31, 2018, when the unrealized risk management net mark-to-market value was a $9.5 million asset which resulted in the $25.4 million unrealized hedging gain recorded in the fourth quarter of 2018. As at February 28, 2019, the net asset mark-to-market value has decreased since year end due to the increase in WTI USD/bbl price to $57.22.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2018, 2019, 2020 and 2021. 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 10 of the Company's consolidated financial statements as at and for the year ended December 31, 2018. The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The 1,525 bbl/d average oil hedged for 2019 represents 53% of fourth quarter 2018 average liquids (oil and NGL) production. The 16,750 GJ/day average natural gas hedged for 2019 represents 55% of fourth quarter average natural gas production.

The following table summarizes the average and minimum and maximum cap and floor prices for the 2019 to 2021 oil and natural gas contracts outstanding as at the date of this MD&A:

	2019					2020					2021				
	Q1	Q2	Q3	Q4	Avg.(1)	Q1	Q2	Q3	Q4	Avg.(1)	Q1	Q2	Q3	Q4	Avg.(1)
Oil hedged (bbl/d)	1,650	1,400	1,400	1,650	**1,525**	1,150	750	550	350	**700**	—	—	—	—	—
Avg. WTI cap price ($C/bbl)	68.46	67.13	69.26	70.45	**68.88**	72.18	76.92	78.81	76.70	**75.32**	—	—	—	—	—
Avg. WTI floor price ($C/bbl)	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)	21,000	16,333	16,000	13,667	**16,750**	12,500	5,500	3,500	3,167	**6,167**	2,000	—	—	—	**500**
Avg. AECO 7A cap price ($C/GJ)	2.47	1.71	1.70	1.72	**1.95**	1.72	1.55	1.58	1.53	**1.64**	1.50	—	—	—	**1.50**
Avg. AECO 7A floor price ($C/GJ)	2.47	1.71	1.70	1.72	**1.95**	1.72	1.55	1.58	1.53	**1.64**	1.50	—	—	—	**1.50**

(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 ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Operating expense, net (1)	**3,851**	4,744	**15,652**	18,950
Operating expense, net ($/boe)	**5.28**	4.81	**4.75**	5.08

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

Operating expense (presented net of processing income and overhead recoveries) totaled $3.9 million for the fourth quarter of 2018, a 19% decrease from the $4.7 million recorded in the fourth quarter of the prior year. This change is attributable to improved operating efficiencies as well as the 26% decrease in production over the same time period. On a per boe basis, operating expense for the fourth quarter was 10% higher at $5.28 per boe in 2018 compared to $4.81 per boe in 2017. The increase is due to fixed costs allocated over lower production relative to the prior year.

For the twelve months ended December 31, 2018, operating expense (presented net of processing income and overhead recoveries) totaled $15.7 million, a 17% decrease from the $19.0 million incurred in 2017. The decrease is attributable to Petrus' improved operating cost structure and decreased activity related to well workover projects. During the year ended 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 ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Transportation expense	**855**	1,233	**3,789**	4,880
Transportation expense ($/boe)	**1.17**	1.25	**1.15**	1.31

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 $0.9 million or $1.17 per boe in the fourth quarter of 2018 ($1.2 million or $1.25 per boe for the prior year comparative period). The lower transportation expense is related to the 26% decrease in production from the fourth quarter of 2017 to the fourth quarter of 2018.

On a twelve month basis, transportation expense totaled $3.8 million, or $1.15 per boe, compared to $4.9 million or $1.31 per boe in 2017. The decrease is related to the 12% decrease in production from the twelve months ended December 31, 2018 compared to the prior year.

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 ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Gross general and administrative expense	**2,248**	1,681	**8,229**	8,787
Capitalized general and administrative and overhead recoveries	**(1,183)**	(1,415)	**(3,045)**	(5,535)
General and administrative expense	**1,065**	**266**	**5,184**	**3,252**
General and administrative expense ($/boe)	**1.46**	**0.27**	**1.57**	**0.87**

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

General and Administrative Expense ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Personnel, consultants and directors	**1,248**	320	**4,610**	4,803
Office costs	**680**	835	**2,588**	2,929
Regulatory and public company expenses	**320**	526	**1,031**	1,055
Gross general and administrative expense	**2,248**	**1,681**	**8,229**	**8,787**
Capitalized general and administrative expense and overhead recoveries	**(1,183)**	(1,415)	**(3,045)**	(5,535)
General and administrative expense	**1,065**	**266**	**5,184**	**3,252**

Fourth quarter 2018 G&A expense (net of capitalized G&A expense and overhead recoveries) totaled $1.1 million or $1.46 per boe, compared to $0.3 million or $0.27 per boe in the fourth quarter of 2017. Gross G&A expense (before capitalized G&A expense and overhead recoveries) was 34% higher than the prior year ($2.2 million in the fourth quarter of 2018 compared to $1.7 million in the fourth quarter of 2017). The change in fourth quarter G&A is primarily due to the fourth quarter 2017 reversal of $0.9 million short term incentive compensation which had been accrued earlier in 2017. The change in net G&A expense is also related 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 due to higher net G&A expense and lower quarterly average production in 2018 compared to 2017.

G&A expense for the year ended December 31, 2018 totaled $5.2 million or $1.57 per boe compared to $3.3 million or $0.87 per boe for the prior year comparative period. Gross G&A expense (before capitalized G&A expense and overhead recoveries) decreased 6% from $8.8 million in 2017 to $8.2 million in 2018. The decrease is due to fewer personnel and lower related office and software costs. The increase in total 2018 G&A net of capitalized G&A and overhead recoveries 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 costs incurred 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 December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Gross share-based compensation expense	**329**	258	**858**	804
Capitalized share-based compensation	**(70)**	(82)	**(282)**	(301)
Share-based compensation expense	**259**	**176**	**576**	**503**

Share-based compensation expense (net of capitalized portion) was $0.3 million for the fourth quarter of 2018, which is consistent with the $0.2 million recognized in the fourth quarter of the prior year.

On a twelve month basis, share-based compensation expense (net of capitalized portion) for the year ended December 31, 2018 was $0.6 million, which is higher than the prior year comparative period ($0.5 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 December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Interest expense	**2,370**	1,514	**8,272**	6,992
Foreign exchange loss (gain)	**—**	1	**1**	2
Total cash finance expense	**2,370**	1,515	**8,273**	6,994
Deferred financing costs	**174**	406	**637**	406
Accretion on decommissioning obligations	**224**	265	**887**	989
Total finance expense	**2,768**	**2,186**	**9,797**	**8,389**

The Company incurred total finance expense of $2.8 million in the fourth quarter of 2018, comprised of $0.2 million of non-cash accretion of its decommissioning obligations, $2.4 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 (as each is defined herein). In the fourth 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, $0.4 million of amortization of deferred financing fees and $1.5 million cash interest expense.

The Company incurred total finance expense of $9.8 million for the year ended December 31, 2018, compared to $8.4 million in 2017. The increases in finance expense are due to increases in interest expense from 2017 to 2018 during both the fourth quarter and the year are due to increases in the underlying prime interest rate. These increases were partially offset by reductions in the amount borrowed under 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 ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Depletion and depreciation expense	**8,679**	**12,654**	**40,423**	52,614
Depletion and depreciation expense ($/boe)	**11.89**	**12.84**	**12.28**	14.11

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 fourth quarter of 2018 of $8.7 million or $11.89 per boe, compared to the fourth quarter of 2017, when $12.7 million or $12.84 per boe was recorded. On a twelve month basis, the Company recorded $40.4 million or $12.28 per boe in 2018, compared to $52.6 million or $14.11 per boe for the prior year. The decrease is due to lower production volume. In addition, the impairment losses incurred in 2017 contributed to a lower depletion per boe rate.

IMPAIRMENT

The following table illustrates impairment losses recorded in the reporting periods:

Impairment ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Impairment	—	64,000	—	109,000
Total	**—**	**64,000**	**—**	**109,000**

Petrus recognized an impairment loss of nil for the three and twelve months ended December 31, 2018, compared to the prior year comparative periods where an impairment loss of $64.0 million and $109.0 million, respectively, was recorded.

During the year ended 2017, management determined that certain CGUs were no longer considered to be core to the Company. As such, a process was initiated to potentially divest of the Company's Foothills and Central Alberta CGUs. Based on interest in the Foothills and Central Alberta assets and information obtained through the divestiture process to date, the Company determined there were indicators of impairment. The Company recorded an impairment loss of $64.0 million and $109.0 million on its property, plant and equipment and exploration and evaluation assets related to the Foothills and Central Alberta CGUs during the three and twelve month periods ended December 31, 2017, respectively.

As at December 31, 2018, the book value of the Company's net assets was greater than its market capitalization. The Company determined there to be indicators of impairment on the Foothills and Central Alberta CGUs and performed an impairment test on these two CGUs. No impairment charge was recorded as the recoverable amounts were higher than their carrying values. The Company did not identify any indicators of impairment on its Ferrier CGU.

EXPLORATION AND EVALUATION EXPENSE

The following table illustrates exploration and evaluation expense recorded in the reporting periods:

Exploration and Evaluation Expense ($000s)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Twelve months ended December 31, 2018**	Twelve months ended December 31, 2017
Exploration and evaluation expense	**134**	148	**1,938**	2,783
Total	**134**	**148**	**1,938**	**2,783**

LOSS (GAIN) ON SALE OF ASSETS

The following table illustrates the loss (gain) on sale of assets during the reporting periods:

Loss (Gain) on Sale of Assets($000s)	**Three months ended December 31, 2018**	Three months ended December 31, 2017	**Twelve months ended December 31, 2018**	Twelve months ended December 31, 2017
Loss (Gain) on sale of assets	**19**	624	**(8)**	1,542
Total	**19**	**624**	**(8)**	**1,542**

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 December 31, 2018**	**Three months ended December 31, 2017**	**Twelve months ended December 31, 2018**	**Twelve months ended December 31, 2017**
Weighted average Common Shares outstanding				
Basic	**49,492**	49,456	**49,492**	48,825
Fully diluted	**49,492**	49,456	**49,492**	48,825
Common Shares outstanding				
Basic	**49,492**	49,492	**49,492**	49,492
Fully diluted	**49,492**	49,492	**49,492**	49,492
Stock options outstanding	**3,083**	2,915	**3,083**	2,915

At December 31, 2018, the Company had 49,491,840 Common Shares and 3,082,880 stock options outstanding.

The Company issued 1,208,880 stock options during the twelve months ended December 31, 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.
(c) 150,480 stock options were issued on November 19, 2018 at an exercise price of $0.77.

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. At December 31, 2018, 382,796 (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 equivalent to the number of DSUs multiplied by 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 December 31, 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 December 31, 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.

At December 31, 2018, the Company had drawn $97.0 million against the RCF and had a $0.7 million letter of credit outstanding against the RCF (December 31, 2017 – $97.6 million outstanding against the RCF and $0.3 million letter of credit).

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 unanimous lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2019.

(b) Term Loan

At December 31, 2018, the Company had a $35 million (December 31, 2017 – $35 million) Term Loan outstanding (excluding $0.6 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 8 of the Company's December 31, 2018 consolidated financial statements. The Company was in compliance with all financial covenants at December 31, 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 funds flow and available credit capacity from its RCF.

Typically the Company ensures that it has sufficient cash on demand to meet expected operational expenses for a normal period. Toachieve 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 December 31, 2018, the Company had a working capital deficiency (excluding risk management assets and liabilities and director share unit liabilities) of $7.8 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 December 31, 2018:

$000s	Total	< 1 year	1-5 years
Accounts payable	21,646	21,646	—
Bank indebtedness and long term debt[(1)]	132,380	380	132,000
Total	**154,026**	**22,026**	**132,000**

[(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	775	715	60	—
Firm service transportation	19,739	1,374	12,870	5,495
Total commitments	**20,515**	**2,089**	**12,930**	**5,495**

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 10 and 15 of the Company's December 31, 2018 consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $12.7 million in the fourth quarter of 2018, compared to $21.9 million in the fourth quarter of the prior year. For the twelve months ended December 31, 2018, Petrus invested $24.1 million compared to $72.8 million in 2017. The decrease in capital spending is related to decreased capital activity as a result of lower natural gas commodity pricing, as well as the Company's strategic decision to allocate funds flow to debt reduction. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Drill and complete	**10,503**	17,435	**16,510**	51,283
Oil and gas equipment	**1,636**	3,619	**4,177**	18,618
Geological	**—**	—	**—**	227
Land and lease	**23**	—	**1,635**	343
Office	**60**	105	**58**	197
Capitalized general and administrative	**438**	726	**1,718**	2,082
Total capital expenditures	**12,660**	**21,885**	**24,098**	**72,750**
Gross (net) wells spud	**6 (2.7)**	**3 (1.4)**	**10 (4.3)**	**19 (13.2)**

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

Acquisitions and Dispositions ($000s)	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Acquisitions	**—**	**789**	**—**	9,578
Dispositions	**(6)**	—	**(448)**	(4,837)
Total acquisitions and dispositions	**(6)**	**789**	**(448)**	**4,741**

Net A&D activity totaled $0.01 million in the three months ended December 31, 2018, compared to the prior year period which totaled $0.79 million. During the year ended December 31, 2018, Petrus divested non-core assets for approximately $0.4 million (compared to net A&D activity in 2017 of $4.8 million).

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	Jun. 30, 2017	Mar. 31, 2017
Average Production								
Natural gas (mcf/d)	30,480	33,461	39,126	45,543	46,625	45,550	42,392	40,332
Oil (bbl/d)	1,358	1,243	1,484	1,530	1,854	1,877	2,015	1,542
NGLs (bbl/d)	1,496	1,519	1,241	1,475	1,086	1,098	1,160	1,067
Total (boe/d)	**7,934**	**8,338**	**9,246**	**10,596**	**10,711**	**10,567**	**10,240**	**9,331**
Total (boe)	**730,819**	**767,095**	**841,316**	**953,598**	**985,388**	**972,140**	**931,821**	**839,746**
Financial Results								
Oil and natural gas revenue	16,064	20,030	19,321	25,301	23,243	18,299	26,753	22,274
Royalty expense	(2,436)	(2,391)	(2,137)	(4,674)	(3,000)	(2,656)	(4,306)	(3,309)
Net oil and natural gas revenue	**13,628**	**17,639**	**17,184**	**20,627**	**20,243**	**15,643**	**22,447**	**18,965**
Transportation expense	(855)	(749)	(988)	(1,197)	(1,233)	(1,255)	(1,235)	(1,157)
Operating expense	(3,851)	(3,800)	(3,841)	(4,160)	(4,744)	(5,271)	(5,155)	(3,780)
Operating netback	**8,922**	**13,090**	**12,355**	**15,270**	**14,266**	**9,117**	**16,057**	**14,028**
Realized gain (loss) on derivatives	(573)	(2,061)	(625)	298	1,210	1,829	212	482
Other income	268	69	103	—	—	—	—	—
General & administrative expense	(1,065)	(1,317)	(1,372)	(1,430)	(266)	(1,059)	(1,047)	(882)
Cash finance expense	(2,370)	(1,941)	(2,097)	(1,865)	(1,515)	(1,936)	(1,807)	(1,736)
Decommissioning expenditures	(152)	(155)	—	(168)	(611)	(224)	(957)	(160)
Corporate netback and funds flow	**5,030**	**7,685**	**8,364**	**12,105**	**13,084**	**7,727**	**12,458**	**11,732**
Oil and natural gas revenue	**16,064**	**20,030**	**19,321**	**25,301**	**23,243**	**18,299**	**26,753**	**22,274**
Per share - basic	0.32	0.40	0.39	0.51	0.47	0.37	0.54	0.48
Per share - fully diluted	0.32	0.40	0.39	0.51	0.47	0.37	0.54	0.47
Net income (loss)	**21,063**	**(8,048)**	**(10,615)**	**(5,684)**	**(67,095)**	**(50,696)**	**(781)**	**7,311**
Per share - basic	0.43	(0.16)	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.15
Per share - fully diluted	0.43	(0.16)	(0.21)	(0.11)	(1.36)	(1.03)	(0.02)	0.16
Common shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,492	49,492	49,428	49,428	49,428
Fully diluted	49,492	49,492	49,492	49,492	49,492	49,428	49,428	52,664
Weighted avg. shares outstanding (000s)								
Basic	49,492	49,492	49,492	49,492	49,456	49,428	49,428	46,754
Fully diluted	49,492	49,492	49,492	49,492	49,456	49,428	49,428	46,989
Total assets	341,820	322,335	330,359	343,161	353,445	409,078	465,794	460,095
Net debt	**(139,214)**	**(131,603)**	**(135,111)**	**(142,238)**	**(148,066)**	**(137,531)**	**(137,069)**	**(130,624)**

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and corporate netback are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus’ average quarterly production decreased from 9,331 boe/d in the first quarter of 2017 to 7,934 boe/d in the fourth quarter of 2018. The 15% 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.

SELECTED ANNUAL INFORMATION

($000s unless otherwise noted)

For the year ended,	December 31, 2018	December 31, 2017	December 31, 2016
Oil and natural gas revenue	**80,716**	**90,569**	**64,840**
Per share - basic	1.63	1.85	1.46
Per share - fully diluted	1.63	1.85	1.46
Net loss	**(3,284)**	**(111,261)**	**(67)**
Per share - basic	(0.07)	(2.28)	(1.51)
Per share - fully diluted	(0.07)	(2.28)	(1.51)
Common shares outstanding (000s)			
Basic	49,492	49,492	45,349
Fully diluted	49,492	49,492	45,349
Weighted avg. shares outstanding (000s)			
Basic	49,492	48,825	44,429
Fully diluted	49,492	48,825	44,429
Total assets	**341,820**	**353,445**	**439,967**
Non-current liabilities	**171,646**	**173,272**	**118,934**

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 consolidated financial statements as at and for the year ended December 31, 2018.

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, 2018.

New standards and interpretations

IFRS 9 - Financial Instruments
On January 1, 2018, Petrus adopted IFRS 9 Financial Instruments, which includes a principle-based approach for classification and measurement of financial assets and a forward-looking 'expected credit loss' model. The classification and measurement of financial instruments under IFRS 9 did not have a material impact on Petrus' consolidated financial statements. In addition, the application of the expected credit loss model to financial assets classified as amortized cost did not result in a material adjustment on transition. IFRS 9 was applied retrospectively in accordance with transition requirements with no impact to opening retained earnings or comparative periods.

IFRS 15 - Revenue from Contracts with Customers
Petrus adopted IFRS 15 "Revenue from Contracts with Customers" effective January 1, 2018, which establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Petrus' revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices. Petrus adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15. The adoption of IFRS 15 did not materially impact the timing or measurement of revenue. However, IFRS 15 contains new disclosure requirements.

IFRS 16 - Leases

IFRS 16 was issued in January 2016 and it replaces IAS 17 Leases, IFRIC 4 Determining whether an Arrangement contains a Lease, SIC-15 Operating Leases-Incentives and SIC-27 Evaluating the Substance of Transactions Involving the Legal Form of a Lease. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases and requires lessees to account for all leases under a single on-balance sheet model similar to the accounting for finance leases under IAS 17. The standard includes two recognition exemptions for lessees – leases of 'low-value' assets (e.g., personal computers) and short-term leases (i.e., leases with a lease term of 12 months or less). At the commencement date of a lease, a lessee will recognize a liability to make lease payments (i.e., the lease liability) and an asset representing the right to use the underlying asset during the lease term (i.e., the right-of-use asset). Lessees will be required to separately recognize the interest expense on the lease liability and the depreciation expense on the right-of-use asset.

Lessees will be also required to remeasure the lease liability upon the occurrence of certain events (e.g., a change in the lease term, a change in future lease payments resulting from a change in an index or rate used to determine those payments). The lessee will generally recognize the amount of the remeasurement of the lease liability as an adjustment to the right-of-use asset.

IFRS 16 is effective for annual periods beginning on or after January 1, 2019. A lessee can choose to apply the standard using either a full retrospective or a modified retrospective approach. The standard's transition provisions permit certain reliefs. Petrus is finalizing its review of identified leases and arrangements qualifying as leases under IFRS 16 and is in the process of determining the financial impact of identified leases on its consolidated financial statements. Petrus expects to adopt IFRS 16 using the modified retrospective approach.

On initial adoption, the Company expects to use the following practical expedients permitted under the standard:

1. Apply a single discount rate to a portfolio of leases with similar characteristics;
2. Account for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
3. Account for lease payments as an expense and not recognize a right-of-use ("ROU") asset if the underlying asset is of low dollar value;
4. The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease; and

The Company has identified ROU assets and lease liabilities primarily related to office space. The Company has completed an initial assessment but not yet finalized the potential impact on its consolidated financial statements.

Disclosure Controls and Procedures

Petrus' Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual 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 Chief Executive Officer and Chief Financial Officer of Petrus have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2018 and have concluded that the Company's DC&P are effective at December 31, 2018 for the foregoing purposes.

Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in NI 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets of Petrus; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Petrus are being made in accordance with authorizations of management and Directors of Petrus; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Petrus. For the year ended December 31, 2018, they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the Company's ICFR is the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Petrus conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2018. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as at December 31, 2018, Petrus maintained effective ICFR. It should be noted that while the Chief Executive Officer and Chief Financial Officer believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system 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 natural gas industry which is a useful supplemental measure to evaluate the specific operating performance by product at the oil and natural 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.

Funds Flow and Corporate Netback

Corporate netback is a common non-GAAP financial measure used in the oil and natural gas industry which evaluates the Company's profitability at the corporate level. Corporate netback is equal to funds flow which is a directly comparable GAAP measure. Petrus analyzes these measures on an absolute value and per unit basis. Management believes that funds flow and corporate netback provide 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 other income and the net realized gain (loss) on financial derivatives.

	Three months ended Dec. 31, 2018		Three months ended Dec. 31, 2017		Twelve months ended Dec. 31, 2018		Twelve months ended Dec. 31, 2017	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	16,064	22.01	23,243	23.59	80,716	24.52	90,569	24.28
Royalty expense	(2,436)	(3.34)	(3,000)	(3.04	(11,638)	(3.54)	(13,270)	(3.56)
Net oil and natural gas revenue	**13,628**	**18.67**	**20,243**	**20.55**	**69,078**	**20.98**	**77,299**	**20.72**
Transportation expense	(855)	(1.17)	(1,233)	(1.25	(3,789)	(1.15)	(4,880)	(1.31)
Operating expense	(3,851)	(5.28)	(4,744)	(4.81	(15,652)	(4.75)	(18,950)	(5.08)
Operating netback	**8,922**	**12.22**	**14,266**	**14.49**	**49,637**	**15.08**	**53,469**	**14.33**
Realized gain (loss) on financial derivatives	(573)	(0.79)	1,210	1.23	(2,961)	(0.90)	3,732	1.00
Other income	267	0.37	—	—	440	0.13	—	—
General & administrative expense	(1,065)	(1.46)	(266)	(0.27	(5,184)	(1.57)	(3,252)	(0.87)
Cash finance expense	(2,370)	(3.25)	(1,515)	(1.54	(8,273)	(2.51)	(6,994)	(1.88)
Decommissioning expenditures	(151)	(0.21)	(611)	(0.62	(475)	(0.14)	(1,952)	(0.52)
Funds flow and corporate netback	**5,030**	**6.88**	**13,084**	**13.29**	**33,184**	**10.09**	**45,003**	**12.06**

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 deferred share unit 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 December 31, 2018**	**As at December 31, 2017**
Adjusted current assets [(1)]	**14,035**	13,042
Less: adjusted current liabilities [(1)]	**(21,827)**	(29,201)
Less: long term debt	**(131,422)**	(131,907)
Net debt	**(139,214)**	**(148,066)**

[(1)] *Adjusted for unrealized risk management assets, liabilities and unrealized deferred share units liabilities.*

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, 2018, 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.

This MD&A contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs" or "F&D", "finding, development and acquisition costs" or "FD&A", "future development cost" or "FDC", "reserve life index" and "reserve replacement ratio." These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon.

F&D and FD&A Costs

FD&A cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period. F&D cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period, excluding acquisitions and dispositions. Both F&D and FD&A costs take into account reserve revisions during the year on a per boe basis. The methodology used to calculate F&D costs includes disclosure required to bring the proved undeveloped and probable reserves to production. Annually, changes in forecast FDC occur as a result of Petrus' development, acquisition and disposition activities, undeveloped reserve revision and capital cost estimates. These values reflect the independent evaluator's best estimate of the cost to bring the proved and probable undeveloped reserves to production.

Reserve Life Index

Reserve life index is defined as total reserves by category divided by the annualized fourth quarter production.

Reserve Replacement Ratio

The reserve replacement ratio is calculated by dividing the yearly change in reserves net of production by the actual annual production for the year.

Reserve Recycle Ratio

The reserve replacement ratio is calculated by dividing field netback by FD&A.

Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Petrus' operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment.

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, 2018. 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, statements with respect to: Petrus' business plan and capital expenditure program for 2019, including its first quarter capital budget and the funding of the same; Petrus' drilling plan, including the same being within funds flow; expected 2019 quarterly debt repayment; Petrus' liquid weighting; the results and success of Petrus' hedging program; the growth of Petrus; expectations regarding Petrus' balance sheet; expectations regarding the adequacy of Petrus' liquidity and the funding of its financial liabilities; expected year over year production; sources of and sufficient financing and the requirement therefor; expected funds flow for the first quarter of 2019; the performance characteristics of the Company's crude oil, NGL and natural gas properties including estimated production and production dates; Petrus' adoption of IFRS 16 and the impact of the same; the development of the Company's Cardium light oil in Ferrier; future prospects; the focus of and timing of capital expenditures; access to debt and equity markets; projections of market prices and costs; 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; Petrus' future operating and financial results; capital investment programs; 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.

This MD&A discloses drilling locations, which are proved plus probable locations as at December 31, 2018 based on the Sproule Report. The drilling locations on which the Company will actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

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*
mboe	*barrel of oil equivalent*
mmboe	*thousand barrel of oil equivalent*
boe/d	*million 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*

CONSOLIDATED ANNUAL FINANCIAL STATEMENTS

As at and for the years ended December 31, 2018 and 2017

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Petrus Resources Ltd.

Opinion

We have audited the consolidated financial statements of Petrus Resources Ltd. (the Company), which comprise the consolidated balance sheets as at December 31, 2018 and 2017, and the consolidated statements of net loss and comprehensive loss, consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018 and 2017, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

We obtained the Annual Report prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Janet Huang.

Ernst & Young LLP

Calgary, Alberta
March 13, 2019

CONSOLIDATED BALANCE SHEETS

(Presented in 000's of Canadian dollars)

As at	December 31, 2018	December 31, 2017
ASSETS		
Current		
Cash	63	24
Deposits and prepaid expenses	1,297	1,430
Accounts receivable *(note 15)*	12,675	11,588
Risk management asset *(note 10)*	6,786	2,163
Total current assets	**20,821**	**15,205**
Non-current		
Risk management asset *(note 10)*	2,749	572
Exploration and evaluation assets *(notes 5 and 6)*	42,410	43,197
Property, plant and equipment *(notes 5 and 7)*	275,840	294,471
Total assets	**341,820**	**353,445**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness *(note 15)*	380	3,844
Accounts payable and accrued liabilities *(note 15)*	21,646	25,601
Total current liabilities	**22,026**	**29,445**
Non-current liabilities		
Long term debt *(note 8)*	131,422	131,907
Decommissioning obligation *(note 9)*	40,224	40,654
Risk management liability *(note 10)*	—	711
Total liabilities	**193,672**	**202,717**
Shareholders' equity		
Share capital *(note 11)*	430,119	430,119
Contributed surplus	8,384	7,680
Deficit	(290,355)	(287,071)
Total shareholders' equity	**148,148**	**150,728**
Total liabilities and shareholders' equity	**341,820**	**353,445**

Commitments (note 19)
See accompanying notes to the consolidated financial statements

Approved by the Board of Directors,

(signed) "Don T. Gray"

Don T. Gray
Chairman

(signed) "Donald Cormack"

Donald Cormack
Director

CONSOLIDATED STATEMENTS OF NET LOSS AND COMPREHENSIVE LOSS

(Presented in 000's of Canadian dollars, except per share amounts)

	Year ended December 31, 2018	Year ended December 31, 2017
REVENUE		
Oil and natural gas revenue *(note 21)*	**80,716**	**90,569**
Royalty expense	(11,638)	(13,270)
Net oil and natural gas revenue	**69,078**	**77,299**
Other income	440	—
Net gain on financial derivatives *(note 10)*	4,549	13,353
	74,067	**90,652**
EXPENSES		
Operating *(note 13)*	15,652	18,950
Transportation	3,789	4,880
General and administrative *(note 14)*	5,184	3,252
Share-based compensation *(note 11)*	576	503
Finance *(note 17)*	9,797	8,389
Exploration and evaluation *(note 6)*	1,938	2,783
Depletion and depreciation *(note 7)*	40,423	52,614
Loss (gain) on sale of assets *(note 5)*	(8)	1,542
Impairment *(notes 6 and 7)*	—	109,000
Total expenses	**77,351**	**201,913**
NET LOSS AND COMPREHENSIVE LOSS	**(3,284)**	**(111,261)**
Net loss per common share		
Basic and diluted *(note 12)*	**$ (0.07)**	**$ (2.28)**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Presented in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Total
Balance, December 31, 2016	**419,672**	**7,409**	**(175,810)**	**251,271**
Net loss	—	—	(111,261)	(111,261)
Issuance of common shares	10,498	(96)	—	10,402
Share issue costs	(51)	—	—	(51)
Share-based compensation	—	367	—	367
Balance, December 31, 2017	**430,119**	**7,680**	**(287,071)**	**150,728**
Net loss	—	—	(3,284)	(3,284)
Share-based compensation	—	704	—	704
Balance, December 31, 2018	**430,119**	**8,384**	**(290,355)**	**148,148**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Presented in 000's of Canadian dollars)

	Year ended December 31, 2018	Year ended December 31, 2017
OPERATING ACTIVITIES		
Net loss	**(3,284)**	**(111,261)**
Adjust items not affecting cash:		
Share-based compensation *(note 11)*	576	503
Unrealized gain on financial derivatives (*note 10)*	(7,510)	(9,621)
Non-cash finance expenses *(note 17)*	1,524	1,395
Depletion and depreciation *(note 7)*	40,423	52,614
Impairment *(notes 6 and 7)*	—	109,000
Exploration and evaluation expense *(note 6)*	1,938	2,783
Loss (gain) on sale of assets *(note 5)*	(8)	1,542
Decommissioning expenditures *(note 9)*	(475)	(1,952)
Funds flow	**33,184**	**45,003**
Change in operating non-cash working capital *(note 18)*	(4,764)	931
Cash flows from operating activities	**28,420**	**45,934**
FINANCING ACTIVITIES		
Issue of common shares *(note 11)*	—	10,429
Share issue costs *(note 11)*	—	(51)
Repayment of term loan	—	(7,000)
Increase (repayment) of revolving credit facility	(600)	23,833
Increase (repayment) in bank indebtedness	(3,464)	3,844
Transaction costs on debt	(350)	(1,541)
Change in financing non-cash working capital *(note 18)*	298	(847)
Cash flows from (used in) financing activities	**(4,116)**	**28,667**
INVESTING ACTIVITIES		
Property and equipment acquisitions *(note 5)*	(285)	(1,770)
Property and equipment dispositions *(note 5)*	50	4,837
Exploration and evaluation asset acquisitions *(note 5)*	(92)	(8,000)
Exploration and evaluation asset expenditures *(note 6)*	(1,486)	(829)
Petroleum and natural gas property expenditures *(note 7)*	(21,777)	(71,723)
Other capital expenditures *(note 7)*	(60)	(198)
Change in investing non-cash working capital *(note 18)*	(615)	2,826
Cash flows (used in) investing activities	**(24,265)**	**(74,857)**
Increase (decrease) in cash	39	(256)
Cash, beginning of year	24	280
Cash, end of year	**63**	**24**
Cash interest paid	8,272	6,992

See accompanying notes to the consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the years ended December 31, 2018 and 2017

1. NATURE OF THE ORGANIZATION

Petrus Resources Ltd. (the "Company" or "Petrus") was incorporated under the laws of the Province of Alberta on November 25, 2015. The principal undertaking of Petrus is the investment in energy business-related assets. The operations of the Company consist of the acquisition, development, exploration and exploitation of these assets. These consolidated financial statements reflect only the Company's proportionate interest in such activities and are comprised of the Company and its subsidiaries, Petrus Resources Corp. and Petrus Resources Inc.

The Company's head office is located at 2400, 240 - 4th Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements, for the years ended December 31, 2018 and 2017, were approved by the Company's Audit Committee and Board of Directors on March 13, 2019.

2. BASIS OF PRESENTATION

Statement of Compliance

(a) Statement of Compliance

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

(b) Measurement Basis

These consolidated financial statements were prepared on the basis of historical cost except for financial derivatives which are measured at fair value. This method is consistent with the method used in prior years. These consolidated financial statements are presented in Canadian dollars.

(c) Consolidation

These audited consolidated financial statements include the accounts of Petrus and its 100% owned subsidiaries, Petrus Resources Corp. and Petrus Resources Inc. Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company haspower over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns. All intra-group balances and transactions are eliminated on consolidation.

(d) 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.

Depletion and reserve estimates

Petroleum and natural gas assets are depleted on a unit of production basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The calculation incorporates the estimated future cost of developing and extracting those reserves. Proved and probable reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Reserves estimates, although not reported as part of the Company's financial statements, can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion and depreciation, decommissioning liabilities, deferred taxes, asset impairments and business combinations. Independent reservoir engineers perform evaluations of the Company's petroleum and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable petroleum and natural gas reserves are based upon a number ofvariables and assumptions such as geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available or as economic conditions change.

Impairment indicators and cash-generating units

For purposes of impairment testing, exploration and evaluation assets and petroleum and natural gas assets are aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment.

The recoverable amounts of CGU's and individual assets have been determined based on the higher of the value-in-use calculations and fair value less costs of disposal. These calculations require the use of estimates and assumptions, including the discount rate, future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available and changes in economic conditions take place. Changes may impact the estimated life of the field and economical reserves recoverable and may require a material adjustment to the carrying value of exploration and evaluation assets and petroleum and natural gas assets. The Company monitors internal and external indicators of impairment relating to its tangible assets.

Technical feasibility and commercial viability of exploration and evaluation assets
The determination of technical feasibility and commercial viability, based on the presence of proved and probable reserves, results in the transfer of assets from exploration and evaluation assets to property, plant and equipment. As discussed above, the estimate of proved and probable reserves is inherently complex and requires significant judgment. Thus any material change to reserve estimates could affect the technical feasibility and commercial viability of the underlying assets.

Financial Instruments
Financial instruments are subject to valuations at the end of each reporting period. Generally the valuation is based on active and efficient markets. However, certain financial instruments may not be traded on an efficient market or the market may disappear or be subject to conditions that impede the efficiency of the market.

Decommissioning obligation
At the end of the operating life of the Company's facilities and properties and upon retirement of its petroleum and natural gas assets, decommissioning costs will be incurred by the Company. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and discount rates to determine the present value of these cash flows.

Income taxes
Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in income or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods. Income taxes are subject to measurement uncertainty. Significant judgment can be involved in the recognition of deferred tax assets.

Measurement of share-based compensation
Share-based compensation recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Business combinations
Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and petroleum and natural gas assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the purchase price allocation.

Contingencies
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Revenue recognition

Revenue from contracts with customers is recognized when or as Petrus satisfies a performance obligation by transferring a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids usually occurs at a point in time and coincides with title passing to the customer and the customer taking physical possession. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period.

(b) Exploration & evaluation assets

Capitalization
All costs incurred after the rights to explore an area have been obtained, such as geological and geophysical costs, other direct costs of exploration (drilling, testing and evaluating the technical feasibility and commercial viability of extraction) and appraisal and including any directly attributable general and administration costs and share-based payments, are accumulated and capitalized as exploration and evaluation assets.

Certain costs incurred prior to acquiring the legal rights to explore are charged directly to net income (loss).

Depletion & depreciation

Exploration and evaluation costs are not amortized prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant exploration and evaluation asset will be reclassified as a property, plant and equipment asset into the CGU to which it relates, but only after the carrying value of the relevant exploration and evaluation asset has been assessed for impairment and, where appropriate, its carrying value adjusted. Technical feasibility and commercial viability are considered to be demonstrable when proved or probable reserves are determined to exist. If it is determined that technical feasibility and commercial viability have not been achieved in relation to the exploration and evaluation assets appraised, all other associated costs are written down to the recoverable amount in net income (loss).

Expired land leases included as undeveloped land in exploration and evaluation assets are recognized in exploration and evaluation cost in net income (loss) upon expiry and are considered prior to expiry. Management considers upcoming land lease expiries and may recognize the costs in advance of expiry.

Impairment

Indicators of impairment of exploration and evaluation assets are assessed at each reporting date which can include upcoming land lease expiries, third party land valuations and other information . When there are such indications, an impairment test is carried out and any resulting impairment loss is written off to net income (loss). The recoverable amount is the greater of fair value, less costs of disposal, or value-in-use.

(c) Property, plant and equipment

The Company's property, plant and equipment is comprised of petroleum and natural gas assets and corporate assets.

Capitalization

Petroleum and natural gas assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses, if any. Petroleum and natural gas assets consists of the purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use. Petroleum and natural gas assets include developing and producing interests such as land acquisitions, geological and geophysical costs, facility and production equipment, including any directly attributable general and administration costs and share-based payments and the initial estimate of the costs of dismantling and removing an asset and restoring the site on which it was located.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as developing and producing petroleum and natural gas interests when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves, and are accumulated on a field or geotechnical area basis. The cost of day-to-day servicing of an item of petroleum and natural gas assets is expensed in income or loss as incurred. Petroleum and natural gas assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from the disposal of an asset, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in net income or loss.

Depletion and depreciation

The costs for petroleum and natural gas properties, including related pipelines and facilities, are depleted using a unit-of-production method based on the commercial proved and probable reserves.

Petroleum and natural gas assets are not depleted until production commences. This depletion calculation includes actual production in the period and total estimated proved and probable reserves attributable to the assets being depleted, taking into account total capitalized costs plus estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production (before royalties) are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Proved and probable reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

Corporate assets are recorded at cost less accumulated depreciation. Depreciation is calculated on a declining balance method so as to write off the cost of these assets, less estimated residual values, over their estimated useful lives consistent with the treatment used for tax purposes.

Impairment

The assessment for impairment entails comparing the carrying value of the CGU with its recoverable amount: that is, the higher of fair value, less costs of disposal, and value in use. Petrus' property, plant and equipment are grouped into CGUs based on separately identifiable and largely independent cash inflows considering geological characteristics, shared infrastructure and exposure to market risks. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent reservoir engineers.

The CGU's are reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate that the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income (loss).

The recoverable amount is the higher of fair value, less costs of disposal, and the value-in-use. Fair value, less costs of disposal, is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

Impairments of property, plant and equipment are reversed when there is significant evidence that the impairment has been reversed, but only to the extent of what the carrying amount would have been had no impairment been recognized.

(d) Business combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in net income (loss). Transaction costs associated with a business combination are expensed as incurred.

(e) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and reclamation requirements. Costs related to these abandonment activities are estimated by management in consultation with the Company's engineers based on risk-adjusted current costs which take into consideration current technology in accordance with existing legislation and industry practices.

Decommissioning obligations are measured at the present value of the best estimate of expenditures required to settle the obligations at the reporting date. When the fair value of the liability is initially measured, the estimated cost, discounted using a risk-free rate, is capitalized by increasing the carrying amount of the related petroleum and natural gas assets. The increase in the provision due to the passage of time, or accretion, is recognized as a finance expense. Increases and decreases due to revisions in the estimated future cash flows are recorded as adjustments to the carrying amount of the related petroleum and natural gas assets.

Actual costs incurred upon settlement of the liability are charged against the obligation to the extent that the obligation was previously established. The carrying amount capitalized in petroleum and natural gas assets is depleted in accordance with the Company's depletion policy. The Company reviews the obligation at each reporting date and revisions to the estimated timing of cash flows, discount rates and estimated costs will result in an increase or decrease to the obligations. Any difference between the actual costs incurred upon settlement of the obligation and recorded liability is recognized as an increase or reduction in income.

(f) Finance expenses

Finance expense may be comprised of interest expense on borrowings, acquisition related (transaction) costs, foreign exchange expenses and accretion of the discount on decommissioning obligations.

(g) Financial instruments

Financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, financial instruments are measured based on their classification as described below:

- Fair value through profit or loss: Financial instruments under this classification include risk management assets and liabilities.
- Amortized cost: Financial instruments under this classification include cash, accounts receivable, deposits, bank indebtedness, accounts payable and long term debt.

(h) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a reduction in share capital, net of any tax effects.

(i) Flow-through shares

The resources expenditure deductions for income tax purposes related to exploratory activities funded by flow-through shares are renounced to investors in accordance with tax legislation. Upon issuance of a flow-through share, a liability is recognized representing the premium paid on flow-through common shares over regular common shares. This liability is reduced as the expenditures are incurred and tax attributes are renounced.

(j) Income taxes

The Company's income tax expense is comprised of current and deferred tax. Income tax expense is recognized through income or loss except to the extent that it relates to items recognized directly in equity, in which case the related income taxes are also recognized in equity.

Current tax is the expected tax payable on taxable income for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable income. Deferred tax liabilities are generally recognized for all taxable temporary differences. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. Assessing the recoverability of deferred tax assets requires management to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in the jurisdictions of Alberta and Canada. The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

(k) Joint arrangements

A portion of the Company's exploration, development and production activities are conducted jointly with others through unincorporated joint operations. These financial statements reflect only the Company's proportionate interest of these joint operations and the proportionate share of the relevant revenue and related costs.

(l) Share-based compensation

Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the qualifying portion of share-based compensation expense directly attributable to the exploration and development activities of exploration and evaluation assets and petroleum and natural gas assets, with a corresponding decrease to share-based compensation expense. At the time the stock options or performance warrants are exercised, the issuance of common shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

For deferred share units ("DSUs") that can be settled in cash or equity at the option of the DSU participants, the fair value of the DSUs is recognized as stock-based compensation expense, with a corresponding increase in accrued liabilities. DSUs are measured at their fair value at each reporting period on a mark-to-market basis.

(m) Earnings per share

Earnings per share are presented for basic and diluted earnings. Basic per share information is computed by dividing the net income (loss) for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of shares for diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of performance warrants and stock options would be used to purchase common shares at the average market price during the period. The treasury stock method also assumes that the deemed proceeds related to unrecognized share-based payments expense are used to repurchase shares at the average market price during the period. Under the treasury stock method, stock options and share warrants have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the options or warrants (they are "in-the-money"). Exercise of in-the-money stock options and share warrants is assumed at the beginning of the year or date of issuance, if later. Should the Company have a loss for the period, stock options and share warrants would be anti-dilutive and therefore will have no effect on the determination of loss per share.

(n) Leases

The determination of whether an arrangement is, or contains a lease is based on the substance of the arrangement at the inception date, whether fulfillment of the arrangement is dependent on the use of a specific asset or the arrangement conveys a right to use an asset. Leases which transfer substantially all the risks and benefits of ownership to the Company are classified as finance leases. The leased asset is recognized at the lower of the fair value of the leased property or the present value of the minimum lease payments. Finance lease assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Other leases are classified as operating leases and payments are amortized on a straight-line basis over the lease term.

(o) New standards and interpretations

IFRS 9 - Financial Instruments

On January 1, 2018, Petrus adopted IFRS 9 Financial Instruments, which includes a principle-based approach for classification and measurement of financial assets and a forward-looking 'expected credit loss' model. The classification and measurement of financial instruments under IFRS 9 did not have a material impact on Petrus' consolidated financial statements. In addition, the application of the expected credit loss model to financial assets classified as amortized cost did not result in a material adjustment on transition. IFRS 9 was applied retrospectively in accordance with transition requirements with no impact to opening retained earnings or comparative periods.

IFRS 15 - Revenue from Contracts with Customers

Petrus adopted IFRS 15 "Revenue from Contracts with Customers" effective January 1, 2018, which establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Petrus' revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices. Petrus adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15. The adoption of IFRS 15 did not materially impact the timing or measurement of revenue. However, IFRS 15 contains new disclosure requirements.

IFRS 16 - Leases

IFRS 16 was issued in January 2016 and it replaces IAS 17 Leases, IFRIC 4 Determining whether an Arrangement contains a Lease, SIC-15 Operating Leases-Incentives and SIC-27 Evaluating the Substance of Transactions Involving the Legal Form of a Lease. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases and requires lessees to account for all leases under a single on-balance sheet model similar to the accounting for finance leases under IAS 17. The standard includes two recognition exemptions for lessees – leases of 'low-value' assets (e.g., personal computers) and short-term leases (i.e., leases with a lease term of 12 months or less). At the commencement date of a lease, a lessee will recognize a liability to make lease payments (i.e., the lease liability) and an asset representing the right to use the underlying asset during the lease term (i.e., the right-of-use asset). Lessees will be required to separately recognize the interest expense on the lease liability and the depreciation expense on the right-of-use asset.

Lessees will be also required to remeasure the lease liability upon the occurrence of certain events (e.g., a change in the lease term, a change in future lease payments resulting from a change in an index or rate used to determine those payments). The lessee will generally recognize the amount of the remeasurement of the lease liability as an adjustment to the right-of-use asset.

IFRS 16 is effective for annual periods beginning on or after January 1, 2019. A lessee can choose to apply the standard using either a full retrospective or a modified retrospective approach. The standard's transition provisions permit certain reliefs. Petrus is finalizing its review of identified leases and arrangements qualifying as leases under IFRS 16 and is in the process of determining the financial impact of identified leases on its consolidated financial statements. Petrus expects to adopt IFRS 16 using the modified retrospective approach.

On initial adoption, the Company expects to use the following practical expedients permitted under the standard:

1. Apply a single discount rate to a portfolio of leases with similar characteristics;
2. Account for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
3. Account for lease payments as an expense and not recognize a right-of-use ("ROU") asset if the underlying asset is of low dollar value;
4. The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease; and

The Company has identified ROU assets and lease liabilities primarily related to office space. The Company has completed an initial assessment but not yet finalized the potential impact on its consolidated financial statements.

4. DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Petroleum and natural gas properties and equipment and exploration and evaluation assets

The fair value of petroleum and natural gas properties and equipment recognized in a business combination and for impairment testing, is based on market values. The market value of petroleum and natural gas properties and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in petroleum and natural gas properties and equipment) and intangible exploration and evaluation assets is estimated with reference to the discounted cash flow expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The fair value less costs of disposal value used to determine the recoverable amount of the impaired petroleum and natural gas properties are classified as Level 3 fair value measurements. Refer to *"Financial Instruments"* section below for fair value hierarchy classifications.

Derivatives

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options is based on option models that use published information with respect to volatility, prices, interest rates and counter-party credit risks.

Share-based payments

The fair value of employee share-based payments is measured using a Black-Scholes option-pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility in share price (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividend yield, risk-free interest rate (based on government bonds) and estimated forfeiture rate at each reporting date.

Financial Instruments

The Company's fair value measurements require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

- Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

- Level 3 - Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Company's risk management contracts are considered Level 2.

5. ACQUISITIONS AND DISPOSITIONS

Asset exchange agreement

On March 13, 2018, Petrus closed a property swap transaction to exchange assets with an arm's length party. The Company recorded a loss of $0.1 million on the asset exchange, net of closing adjustments, during the year ended December 31, 2018.

The following tables summarize the net assets disposed of and acquired pursuant to the swap:

Net assets disposed $000s	
Exploration and evaluation assets ("E&E assets")	1,086
Petroleum and natural gas properties and equipment ("PP&E")	3,231
Decommissioning obligations	(471)
Total net assets disposed	**3,846**

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,013
Petroleum and natural gas properties and equipment	2,852
Decommissioning obligations	(224)
Total net assets acquired	**3,641**

During the year ended December 31, 2018, Petrus incurred approximately $0.2 million in net cash expenditures on other minor acquisition and disposition transactions for E&E assets and PP&E. During the year ended December 31, 2018, the Company recorded a net gain of $0.1 million, net of approximately $0.1 in decommissioning obligation, from the disposition of E&E assets and PP&E for cash proceeds of approximately $0.4 million.

Property disposition - non-core

On August 15, 2017 Petrus closed the disposition of its working interest in certain non-core oil and natural gas properties in the Company's Foothills area for cash consideration of $4.8 million. The assets disposed of included approximately 150 boe/d of production along with related land and infrastructure. The proceeds were utilized to repay indebtedness under the Company's credit facilities. The Company recorded a loss of $1.0 million related to the disposition.

The following table summarizes the net assets disposed pursuant to the disposition:

Net assets disposed $000s	
Exploration and evaluation assets	1,438
Petroleum and natural gas properties and equipment	5,579
Decommissioning obligations	(1,232)
Total net assets disposed	**5,785**

Property acquisition

On February 28, 2017 Petrus closed the acquisition of oil and natural gas assets for total cash consideration of $8.8 million net of closing adjustments. The acquisition included approximately 3,200 undeveloped Cardium leases in is Ferrier core area, approximately 40 boe/d of production and a non-producing well. The purchase price was allocated as follows:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	8,000
Petroleum and natural gas properties and equipment	969
Decommissioning obligations	(151)
Total net assets acquired	**8,818**

Other acquisition and disposition activity

During 2017, Petrus recorded other minor acquisition and disposition transactions for petroleum and natural gas properties and equipment for total net cash consideration of $0.8 million.

6. EXPLORATION AND EVALUATION ASSETS

The components of the Company's exploration and evaluation assets are as follows:

$000s	
Balance, December 31, 2016	**64,824**
Additions	309
Property acquisitions *(note 5)*	8,000
Exploration and evaluation expense	(2,783)
Capitalized G&A	520
Capitalized share-based compensation	75
Property disposition *(note 5)*	(1,438)
Transfers to property, plant and equipment *(note 7)*	(7,036)
Impairment loss	(19,274)
Balance, December 31, 2017	**43,197**
Additions	1,057
Property acquisitions *(note 5)*	402
Exploration and evaluation expense	(1,938)
Capitalized G&A	429
Capitalized share-based compensation *(note 11)*	70
Property dispositions *(note 5)*	(58)
Transfers to property, plant and equipment *(note 7)*	(749)
Balance, December 31, 2018	**42,410**

For the year ended December 31, 2018, the Company incurred exploration and evaluation expense of $1.9 million, which relates to expired and near expiry undeveloped, non-core land (2017 – $2.8 million).

During the year ended December 31, 2018, the Company capitalized $0.4 million of general and administrative expenses ("G&A") (2017 – $0.5 million) and $0.07 million of non-cash share-based compensation directly attributable to exploration activities (2017 – $0.1 million).

During the year ended December 31, 2017, management determined that certain CGUs were no longer considered to be core to the Company. As such, a process was initiated to potentially divest of the Company's Foothills and Central Alberta CGUs. Based on interest expressed in the Foothills and Central Alberta assets and information obtained through the divestiture process to date, the Company determined there were indicators of impairment and estimated the recoverable amounts of the Foothills exploration and evaluation assets to be $2.9 million and the Central Alberta exploration and evaluation assets to be $2.7 million as at December 31, 2017. The Company recorded an impairment loss of $19.3 million during the year ended December 31, 2017.

For the year ended December 31, 2018, Company did not identify any indicators of impairment in the Company's exploration and evaluation assets.

7. PROPERTY, PLANT AND EQUIPMENT

The components of the Company's property, plant and equipment assets are as follows:

$000s	Cost	Accumulated DD&A	Net book value
Balance, December 31, 2016	**714,009**	**(351,806)**	**362,203**
Additions	70,361	—	70,361
Property acquisitions *(note 5)*	1,729	—	1,729
Property (dispositions) *(note 5)*	(15,078)	9,320	(5,758)
Capitalized G&A	1,560	—	1,560
Capitalized share-based compensation	226	—	226
Transfers from exploration and evaluation assets *(note 6)*	7,036	—	7,036
Depletion & depreciation	—	(52,614)	(52,614)
Decrease in decommissioning provision *(note 9)*	(545)	—	(545)
Impairment loss	—	(89,727)	(89,727)
Balance, December 31, 2017	**779,298**	**(484,827)**	**294,471**
Additions	20,549	—	20,549
Property acquisitions *(note 5)*	2,935	—	2,935
Property dispositions *(note 5)*	(3,503)	—	(3,503)
Capitalized G&A	1,288	—	1,288
Capitalized share-based compensation *(note 11)*	212	—	212
Transfers from exploration and evaluation assets *(note 6)*	749	—	749
Depletion & depreciation	—	(40,423)	(40,423)
Decrease in decommissioning provision *(note 9)*	(438)	—	(438)
Balance, December 31, 2018	**801,090**	**(525,250)**	**275,840**

At December 31, 2018, estimated future development costs of $291.2 million (December 31, 2017 – $283.0 million) associated with the development of the Company's proved plus probable undeveloped reserves were included with the costs subject to depletion. During the year ended December 31, 2018, the Company capitalized $1.3 million of general and administrative expenses ("G&A") (2017 – $1.6 million) and non-cash share-based compensation of $0.2 million, respectively (2017 – $0.2 million), directly attributable to development activities.

For the year ended December 31, 2017, the Company recorded property, plant and equipment impairments of $89.7 million. At the end of the third quarter 2017, management determined that certain CGUs were no longer considered to be core to the Company. As such, a process was initiated to potentially divest of the Company's Foothills and Central Alberta CGUs. Based on interest expressed in the Foothills and Central Alberta assets and information obtained through the divestiture process to date, the Company determined there were indicators of impairment and estimated the recoverable amounts, net of decommissioning liabilities, of the Foothills property plant and equipment assets to be $11.3 million and the Central Alberta property plant and equipment assets to be $44.3 million.

As at December 31, 2018, the book value of the Company's net assets was greater than its market capitalization. The Company determined there to be indicators of impairment on the Foothills and Central Alberta CGUs and performed an impairment test on these two CGUs. No impairment charge was recorded as the recoverable amounts were higher than their carrying values. The Company did not identify any indicators of impairment on its Ferrier CGU.

The recoverable amounts were estimated at fair value less costs of disposal, applying an after-tax discount rate ranging from 7% to 9% on the estimated future cashflow and the following forward commodity price estimates:

Year	Canadian Light Sweet 40 API $/Bbl	AECO $/MMbtu
2019	75.27	1.95
2020	77.89	2.44
2021	82.25	3.00
2022	84.79	3.21
2023	87.39	3.30
2024	89.14	3.39
2025	90.92	3.49
2026	92.74	3.58
2027	94.60	3.68
2028	96.49	3.78
2029	98.42	3.88

Escalation rate of 2.0% thereafter.

8. DEBT

At December 31, 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 December 31, 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.

At December 31, 2018, the Company had a $0.7 million letter of credit outstanding against the RCF (December 31, 2017 – $0.3 million) and had drawn $97.0 million against the RCF (December 31, 2017 – $97.6 million).

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 unanimous lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2019.

(b) Term Loan

At December 31, 2018 the Company had a $35 million (December 31, 2017 – $35 million) Term Loan outstanding (excluding $0.6 million of unamortized deferred financing costs), which is due October 8, 2020. The Term Loan bears interest that 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 Company's RCF and Term Loan are subject to certain financial covenants. The following definitions are used in the covenant calculations for both debt instruments:

Debt to EBITDA Ratio

Debt is defined as Petrus' total debt outstanding of the borrower and EBITDA means earnings before interest, taxes, depreciation and amortization.

Working Capital

Working Capital means Current Assets to Current Liabilities whereby Current Assets means on any date of determination, the current assets of Petrus that would, in accordance with IFRS, be classified as of that date as current assets plus any undrawn availability under the RCF, less any non-cash amount required to be included in current assets as the result of the application of IFRS including non-cash commodity and interest rate hedges assets and liabilities and whereby Current Liabilities means, on any date of determination, the liabilities of Petrus that would, in accordance with IFRS, be classified as of that date as current liabilities, excluding (a) non-cash obligations under IFRS including non-cash commodity and interest rate hedges assets and liabilities, and (b) the current portion of long-term debt.

Working Capital Ratio *means the ratio of Current Assets to Current Liabilities as defined above.*

Proved Asset and PDP Asset Coverage Ratio
Means the ratio of (a) Total Adjusted Present Value or (b) PDP Present Value depending on the reserve category, to Total Debt
Whereby Total Adjusted or PDP reserve value means the present value (discounted at 10%) of future net revenues attributable to the respective reserve category based on the reserve report most recently delivered to the lender.

The RCF carries the following covenants:

a. The Company is unable to borrow amounts greater than the RCF limit;
b. Proved Asset and PDP Asset Coverage Ratio (shown below) must be reported at each borrowing base redetermination date, using the most current reserve report and the Net Secured Debt at the date of the annual borrowing base redetermination which will take place on or before May 31, 2019.

The key financial covenants as at December 31, 2018 are summarized in the following table.

Financial Covenant Description	Required Ratio	As at December 31, 2018
Working Capital Ratio	Over 1.00	1.23
Proved Asset Coverage Ratio [1]	Over 1.25	2.38
PDP Asset Coverage Ratio [1]	Over 1.00	1.37
Debt to EBITDA Ratio	Under 3.50	3.16

[1] *Calculations are based upon the Company's December 31, 2018 reserve report evaluated by Sproule Associates Ltd.*

At December 31, 2018 the Company is in compliance with all financial covenants.

9. DECOMMISSIONING OBLIGATION

The decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The estimated future cash flows have been discounted using an average risk free rate of 2.13 percent and an inflation rate of 2.00 percent (December 31, 2017 – 2.22 percent and 2.00 percent, respectively). Changes in estimates in 2017 and 2018 are due to the changes in the risk free rate and changes in the estimated future cash flow to reclaim the wells and facilities. The Company has estimated the net present value of the decommissioning obligations to be $40.2 million as at December 31, 2018 ($40.7 million at December 31, 2017). The undiscounted, uninflated total future liability at December 31, 2018 is $41.6 million ($43.1 million at December 31, 2017). The payments are expected to be incurred over the operating lives of the assets.
The following table reconciles the decommissioning liability:

$000s	
Balance, December 31, 2016	**43,243**
Property acquisitions	151
Property dispositions	(1,232)
Liabilities incurred	2,530
Liabilities settled	(1,952)
Change in estimates	(3,075)
Accretion expense	989
Balance, December 31, 2017	**40,654**
Property acquisitions *(note 3)*	224
Property dispositions *(note 3)*	(629)
Liabilities incurred	393
Liabilities settled	(475)
Change in estimates	(830)
Accretion expense	887
Balance, December 31, 2018	**40,224**

10. FINANCIAL RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table summarizes the financial derivative contracts Petrus had outstanding as at December 31, 2018:

Contract Period	Type	Total Daily Volume (GJ)	Average Price (CDN$/GJ)
Natural Gas Swaps			
Jan. 1, 2019 to Mar. 31, 2019	Fixed price	21,000	$2.47
Apr. 1, 2019 to Oct. 31, 2019	Fixed price	14,000	$1.73
Nov. 1, 2019 to Mar. 31, 2020	Fixed price	7,000	$1.86
Nov. 1, 2019 to Oct. 31, 2020	Fixed price	3,500	$1.58

Contract Period	Type	Total Daily Volume (Bbl)	Average Price (CDN$/Bbl)
Crude Oil Swaps			
Jan. 1, 2019 to Jun. 30, 2019	Fixed price	300	$61.60
Jan. 1, 2019 to Mar. 31, 2019	Fixed price	1,300	$70.00
Apr. 1, 2019 to Jun. 30, 2019	Fixed price	1,100	$68.64
Jul. 1, 2019 to Sep. 30, 2019	Fixed price	700	$70.94
Jul. 1, 2019 to Dec. 31, 2019	Fixed price	700	$67.59
Oct. 1, 2019 to Dec. 31, 2019	Fixed price	600	$70.13
Oct. 1, 2019 to Dec. 31, 2020	Fixed price	350	$76.70
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	800	$70.20
Apr. 1, 2020 to Jun. 30, 2020	Fixed price	400	$77.11
Jul. 1, 2020 to Sep. 30, 2020	Fixed price	200	$82.50
Crude Oil Collars			
Jan. 1, 2019 to Mar. 31, 2019	Costless collar	50	$60.00-69.50

Risk management asset and liability:

$000s At December 31, 2018	Asset	Liability
Current commodity derivatives	6,786	—
Non-current commodity derivatives	2,749	—
	9,535	**—**

$000s At December 31, 2017	Asset	Liability
Current commodity derivatives	2,163	—
Non-current commodity derivatives	572	711
	2,735	**711**

Earnings impact of realized and unrealized gains (losses) on financial derivatives:

$000s	Year ended Dec. 31, 2018	Year ended Dec. 31, 2017
Realized gain (loss) on financial derivatives	(2,961)	3,732
Unrealized gain (loss) on financial derivatives	7,510	9,621
Net gain (loss) on financial derivatives	**4,549**	**13,353**

11. SHARE CAPITAL

Authorized

The authorized share capital consists of an unlimited number of common voting shares without par value and an unlimited number of preferred shares.

Issued and Outstanding

Common shares ($000s *except number of shares*)	Number of Shares	Amount
Balance, December 31, 2016	**45,349,192**	**419,672**
Common shares issued under equity financing (a)	4,078,708	10,319
Common shares issued under the arrangement agreement	63,940	179
Share issue costs	—	(51)
Balance, December 31, 2017 and December 31, 2018	**49,491,840**	**430,119**

Share Issuances

(a) On February 28, 2017 the Company issued 4,078,708 common shares at a price of $2.53 per share through a non-brokered private placement.

SHARE-BASED COMPENSATION

Stock Options

The Company has a stock option plan in place whereby it may issue stock options to employees, consultants and directors of the Company. The aggregate number of shares that may be acquired upon exercise of all options granted pursuant to the plans shall, at any date or time of determination, be equal to ten percent (10%) of the number that is equal to (i) the number of the Company's basic common shares then issued and outstanding; minus (ii) a number equal to five (5) times the number of common shares that are issuable upon exercise of the then outstanding Performance Warrants, if any, minus (iii) a number equal to fifty percent (50%) of the number of common shares that have previously been issued upon the exercise of Performance Warrants, if any.

At December 31, 2018, 3,082,880 (December 31, 2017 – 2,914,930) stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted average exercise price
Balance, December 31, 2016	**1,976,580**	**$6.56**
Granted	1,855,200	$2.26
Exercised	(232,071)	$1.98
Forfeited or expired	(684,779)	$6.61
Balance, December 31, 2017	**2,914,930**	**$4.21**
Granted	1,208,880	$1.14
Forfeited	(492,410)	$5.94
Expired	(548,520)	$3.43
Balance, December 31, 2018	**3,082,880**	**$2.87**
Exercisable, December 31, 2018	**443,700**	**$10.44**

The following table summarizes information about the stock options granted since inception:

Range of Exercise Price	Stock Options Outstanding			Stock Options Exercisable		
	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining life (years)
$0.86 - $2.33	2,750,380	$1.74	1.17	111,200	$2.33	0.03
$9.00 - $16.00	332,500	$12.18	0.65	332,500	$13.15	0.65
	3,082,880	**$2.87**	**1.11**	**443,700**	**$10.44**	**0.49**

During the year ended December 31, 2018 and the year ended December 31, 2017, the Company granted options which vest equally over three (3) years, and upon vesting, expire 30 business days thereafter. The weighted average fair value of each option granted in 2018 of $0.30 (2017 – $0.64) was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2018	2017
Risk free interest rate	1.70% - 1.90%	0.80% - 0.95%
Expected life (years)	1.08 - 3.08	1.08 - 3.08
Estimated volatility of underlying common shares (%)	63% - 65%	65%
Estimated forfeiture rate	20%	20%
Expected dividend yield (%)	0%	0%

Petrus estimated the volatility of the underlying common shares by analyzing the Company's volatility as well as the volatility of peer group public companies with similar corporate structure, oil and gas assets and size.

Deferred Share Unit ("DSU") Plan

The Company has a deferred share unit plan in place whereby it may issue deferred share units to directors of the Company. The aggregate number of shares that may be issued from treasury of Petrus pursuant to the plan shall not exceed: (i) five percent (5%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue; and (ii) ten percent (10%) of the number of issued and outstanding common shares of the Company (on a non-diluted basis) at the date of issue, less the aggregate number of common shares of the Company reserved for issuance under any other share compensation plan.

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.

The compensation expense was calculated using the fair value method based on the weighted average trading price of the Company's shares for the five trading days ending on the reporting period date. At December 31, 2018, 382,796 (December 31, 2017 – 130,038) Deferred Share Units were issued and outstanding.

The following table summarizes the change in accrued compensation liability related to DSUs:

$000s	
Balance, December 31, 2016	—
Change in accrued compensation liability	244
Balance, December 31, 2017	**244**
Change in accrued compensation liability	(45)
Balance, December 31, 2018	**199**

The following table summarizes the Company’s share-based compensation costs:

$000s	Year ended December 31, 2018	Year ended December 31, 2017
Expensed	576	503
Capitalized to exploration and evaluation assets	70	55
Capitalized to property, plant and equipment	212	164
Total share-based compensation	**858**	**722**

12. LOSS PER SHARE

Loss per share amounts are calculated by dividing the net loss for the period attributable to the common shareholders of the Company by the weighted average number of common shares outstanding during the period.

	Year ended December 31, 2018	Year ended December 31, 2017
Net loss for the year ($000s)	**(3,284)**	**(111,261)**
Weighted average number of common shares – basic (000s)	49,492	48,825
Weighted average number of common shares – diluted (000s)	49,492	48,825
Net loss per common share – basic	**($0.07)**	**($2.28)**
Net loss per common share – diluted	**($0.07)**	**($2.28)**

In computing diluted loss per share for the year ended December 31, 2018, 3,082,880 (December 31, 2017 – 2,914,930) outstanding stock options and 296,104 DSUs were considered.

13. OPERATING EXPENSES

The Company's gross operating expenses for the year ended December 31, 2018 were $16.7 million (December 31, 2017 – $20.0 million). For the year ended December 31, 2018, this includes $3.6 million of processing, gathering and compression charges (December 31, 2017 – $6.3 million).

The Company generated processing income recoveries of $1.0 million for the year ended December 31, 2018 (December 31, 2017 – $1.1 million), which reduced the Company's gross operating expenses to $15.7 million for the year ended December 31, 2018 (December 31, 2017 – $19 million).

14. GENERAL AND ADMINISTRATIVE EXPENSES

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

$000s	2018	2017
Personnel, consultants and directors	4,610	4,803
Office costs	2,588	2,929
Regulatory and public company expenses	1,031	1,055
Gross general and administrative expense	8,229	8,787
Capitalized general and administrative expense and overhead recoveries	(3,045)	(5,535)
General and administrative expense	**5,184**	**3,252**

15. FINANCIAL INSTRUMENTS

Risks associated with financial instruments

Credit risk

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risk. Concentration of credit risk is mitigated by marketing the majority of the Company's production to reputable and financially sound purchasers under normal industry sale and payment terms. As is common in the petroleum and natural gas industry in western Canada, Petrus' receivables relating to the sale of petroleum and natural gas are received on or about the 25th day of the following month. Of the $12.7 million of accounts receivable outstanding at December 31, 2018 (December 31, 2017 – $11.6 million), $7.1 million is owed from 4 parties (December 31, 2017 – $8.7 million from 4 parties), and the balances were received subsequent to year end. The Company considers accounts receivable outstanding past 120 days to be 'past due'. At December 31, 2018, the Company had an allowance for doubtful accounts of $0.2 million (December 31, 2017 – $0.1 million). As at December 31, 2018, 99% of Petrus' accounts receivable were aged less than 120 days and 1% of Petrus' accounts receivable were aged greater than 120 days. The Company does not anticipate any significant collection issues.

The Company's risk management assets and cash are with chartered Canadian banks and the Company does not consider these assets to carry material credit risk.

Liquidity risk

At December 31, 2018, the Company had a $110 million RCF (lender consent is required for total borrowings against the RCF exceeding $105 million, see note 8), on which $97.0 million was drawn (December 31, 2017 – $97.6 million). While the Company is exposed to the risk of reductions to the borrowing base of the RCF, the Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through funds flow and available credit capacity from its RCF. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2019.

The following are the contractual maturities of financial liabilities as at December 31, 2018:

$000s	Total	< 1 year	1-5 years
Accounts payable	21,646	21,646	—
Bank indebtedness and long term debt[1]	132,380	380	132,000
Total	**154,026**	**22,026**	**132,000**

[1] *Excludes deferred finance fees.*

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company's cash, bank indebtedness and accounts receivable are not exposed to significant interest rate risk. The RCF and Term Loan are exposed to interest rate cash flow risk as the instruments are priced on a floating interest rate subject to fluctuations in market interest rates. The remainder of Petrus' financial assets and liabilities are not exposed to interest rate risk. A 1% increase in the Canadian prime interest rate during the year ended December 31, 2018 would have increased net loss by approximately $1.3 million which relates to interest expense on the average outstanding RCF and Term Loan during the period assuming that all other variables remain constant (December 31, 2017 – increased net loss by $1.2 million). A 1% decrease in the Canadian prime interest rate during the period would result in an opposite impact on net loss.

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. A significant change in commodity prices can materially impact the Company's borrowing base limit under its Revolving Credit Facility and may reduce the Company's ability to raise capital. Commodity prices for petroleum and natural gas are not only influenced by Canadian and United States demand, but also by world events that dictate the levels of supply and demand.

The Company manages the risks associated with changes in commodity prices by entering into a variety of financial derivative contracts (see note 10). The Company assesses the effects of movement in commodity prices on net loss. When assessing the potential impact of these commodity price changes, the Company believes a $5/CDN WTI/bbl change in the price of oil and a $0.25/GJ change in the price of natural gas are reasonable measures.

As at December 31, 2018, it was estimated that a $0.25/GJ decrease in the price of natural gas would have increased net loss by $1.8 million (December 31, 2017 – $3.6 million). An opposite change in commodity prices would result in an opposite impact on net loss. As at December 31, 2018, it was estimated that a $5.00/CDN WTI/bbl decrease in the price of oil would have increased net loss by $4.0 million (December 31, 2017 – $5.4 million). An opposite change in commodity prices would result in an opposite impact on net loss.

16. CAPITAL MANAGEMENT

The Company's general capital management policy is to maintain a sufficient capital base in order to manage its business to enable the Company to increase the value of its assets and therefore its underlying share value. In the management of capital, the Company includes share capital and total net debt, which is made up of debt and working capital (current assets less current liabilities). The Company manages its capital structure and makes adjustments in light of economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, Petrus may issue new equity, increase or decrease debt, adjust capital expenditures and acquire or dispose of assets.

17. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	**2018**	**2017**
Cash:		
Interest	8,272	6,992
Foreign exchange	1	2
Total cash finance expenses	8,273	6,994
Non-cash:		
Deferred financing costs	637	406
Accretion on decommissioning obligations *(note 9)*	887	989
Total non-cash finance expenses	1,524	1,395
Total finance expenses	**9,797**	**8,389**

18. SUPPLEMENTAL CASH FLOW INFORMATION

The following table reconciles the changes in non-cash working capital as disclosed in the statements of cash flows:

$000s	2018	2017
Source (use) in non-cash working capital:		
Deposits and prepaid expenses	133	(319)
Transaction costs on debt	(18)	—
Accounts receivable	(1,087)	(61)
Accounts payable and accrued liabilities	(4,110)	3,291
	(5,082)	**2,911**
Operating activities	(4,764)	931
Financing activities	298	(847)
Investing activities	(615)	2,826

The following table reconciles the changes in liability resulting from financing activities:

$000s	Bank Indebtedness	Revolving Credit Facility	Term Loan	Total Liabilities from Financing Activities
Balance, December 31, 2017	**3,844**	**97,600**	**34,307**	**135,751**
Cash flows	(3,464)	(600)	—	(4,064)
Non-cash changes	—	—	114	114
Balance, December 31, 2018	**380**	**97,000**	**34,421**	**131,801**

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

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

$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	775	715	60	—
Firm service transportation	19,739	1,374	12,870	5,495
Total commitments	**20,515**	**2,089**	**12,930**	**5,495**

CONTINGENCIES

In the normal course of Petrus' operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty. Petrus does not anticipate that these claims will have a material impact on its financial position.

20. RELATED PARTY TRANSACTIONS

The Company considers its directors and officers to be key management personnel. The following table outlines transactions with key management personnel:

$000s	2018	2017
Salaries, consulting fees, benefits and director fees, gross	1,563	1,690
Share based compensation, gross	274	482
	1,837	**2,172**

On February 28, 2017, the Chairman of the Company acquired 1,585,000 common shares ("Common Shares") of Petrus Resources Ltd. at a price of $2.53 per Common Share, pursuant to a non-brokered private placement of Common Shares (see note 11). The total consideration paid by the Chairman for the acquisition of the 1,585,000 Common Shares was $4,010,050.

21. REVENUE

The following table presents Petrus' oil and natural gas revenue disaggregated by product type:

$000s	2018	2017
Production Revenue		
Oil and condensate sales	35,684	39,633
Natural gas sales	23,453	38,156
Natural gas liquids sales	21,186	12,685
Total oil and natural gas production revenue	**80,323**	**90,474**
Royalty revenue	393	95
Total oil and natural gas revenue	**80,716**	**90,569**

22. DEFERRED INCOME TAXES

$000s	2018	2017
Loss before taxes	(3,284)	(111,261)
Combined federal and provincial tax rate	27.0%	27.0%
Computed "expected" tax recovery	(887)	(30,323)
Increase/(decrease) in taxes resulting from:		
Permanent items	7	5
Share based payments	156	136
Share issuance costs	(95)	(14)
True up and other	(1,135)	(1,264)
Unrecognized deferred income tax asset	1,954	31,460
Deferred tax expense (recovery)	—	—
Effective tax rate	—%	—%

The components of the Company's deferred tax position at December 31, 2018 and 2017 are as follows:

$000s	2018	2017
Exploration and evaluation assets and property, plant and equipment	(12,842)	(1,847)
Asset retirement obligations	—	—
Share issuance costs	278	546
Non capital loss carry-forwards	15,138	1,847
Unrealized hedging loss	(2,574)	(546)
Deferred tax liability	—	—

The Company had non-capital losses of approximately $217.8 million (2017 – $160.9 million) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2027 and onwards.

CORPORATE INFORMATION

OFFICERS

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President and
Chief Executive Officer

Cheree Stephenson, CA, CPA
Vice President, Finance and
Chief Financial Officer

Marcus Schlegel, P. Eng.
Vice President, Engineering

Brett Booth, BA
Vice President, Land

Ross Keilly, BSc, MSc
Vice President, Exploration

DIRECTORS

Don T. Gray
Chairman
Scottsdale, Arizona

Neil Korchinski
Calgary, Alberta

Patrick Arnell
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Donald Cormack
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Stephen White
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SOLICITOR

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Calgary, Alberta

AUDITOR

Ernst & Young LLP
Chartered Professional Accountants
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