Petrus Resources

ANNUAL REPORT

December 31, 2019

2019 HIGHLIGHTS

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report financial and operating results as at and for the three and twelve months ended December 31, 2019 and to provide 2019 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 are available on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

In 2019, the Company's primary objectives were to generate funds flow in excess of capital expenditures to repay debt and to maximize the profitability of its production by increasing its light oil weighting. Petrus generated funds flow of $33.6 million in 2019 and invested approximately half ($18.1 million) to drill 10 gross (3.1 net) Cardium light oil wells in Ferrier. The Company exceeded its debt repayment target for the year and used $15.5 million of its funds flow to reduce net debt(1). Despite average annual production being 8% lower year over year, funds flow was higher in 2019 due to increased light oil weighting, lower costs and improved commodity pricing.

- **Debt repayment** - Reduction of debt is the Company's first and foremost priority. Since December 31, 2015 Petrus has repaid $103 million (45%) of net debt(1). This includes a $55 million reduction of the Company's second lien term loan ("Term Loan") which was $90 million in 2014 and currently has $35 million outstanding. The Company's revolving credit facility ("RCF") and Term Loan are due in 2020 and therefore have been reclassified to current liabilities in the December 31, 2019 consolidated financial statements. The RCF maturity date is May 31, 2020 which was set prior to the Term Loan maturity of October 8, 2020 due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF. Management is currently in discussion with the Term Loan lender and continues to focus on its disciplined debt reduction strategy.

- **Stronger natural gas pricing** - The average benchmark natural gas price in Canada (AECO 5A monthly index) was $2.35/GJ in the fourth quarter, a significant increase from the third quarter 2019 average price of $0.87/GJ. In January 2020 the AECO 5A monthly index was $2.18/GJ. Petrus anticipates the impacts of TC Energy Corporation's previously announced Temporary Service Protocol, continued expansion of the NGTL system in 2020 and 2021 and current Alberta natural gas storage levels will all continue to support Canadian natural gas prices(2).

- **Higher funds flow per share** - Fourth quarter 2019 production of 8,292 boe/d was 5% higher than the prior year and quarterly funds flow per share was $0.19 in 2019, significantly higher (90%) than the $0.10 generated in the prior year.

- **Free funds flow** - In 2019 Petrus generated funds flow of $33.6 million ($0.68 per share), invested $18.1 million of capital to maintain production and exceeded its debt reduction target of $1 to $2 million per quarter; net debt(1) was reduced by $15.5 million. During the fourth quarter of 2019, Petrus generated funds flow of $9.3 million, more than double the funds flow generated in the third quarter.

- **Increased light oil weighting** - Fourth quarter average production included 1,834 bbl/d of light oil, which was a 47% increase from the third quarter. This was attributable to the new wells brought on production during the fourth quarter.

- **Increased light oil reserve volumes** - In 2019, the Company realized Finding Development and Acquisition ("FD&A") costs of $13.31 per boe for PDP reserves. These finding costs were consistent with the best in the Company's history. In 2019, Petrus' development program generated PDP reserve volume additions of 1.3 mmboe which were comprised of 45% light oil. The Company produced 3.0 mmboe during 2019 and ended the year with 11.7 mmboe of PDP reserve volume (34% oil and liquids).

- **Company best operating costs** - Total annual operating costs were 11% lower than 2018 at $4.25 per boe in 2019, which is the lowest in the Company's history (a 68% decrease since 2012). This marks the fourth 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.

- **Non-core asset disposition** - In December 2019, Petrus entered into an agreement for the sale of its oil and natural gas interests in the Foothills area of Alberta to an arm's length private company for total consideration of $1.8 million (the "Disposition"). The Disposition is expected to close in the first quarter of 2020, subject to regulatory approvals. The Company expects it will reduce Petrus' undiscounted, uninflated decommissioning obligation by approximately $7.5 million or 18%. The cash proceeds from the Disposition will be used to reduce the borrowings under the Company's credit facility(2).

2020 Outlook

Petrus' Board of Directors has approved a first quarter 2020 capital budget of $9.0 million to drill 2 (2.0 net) Cardium wells in the Ferrier area. First quarter funds flow combined with proceeds from the previously announced non-core asset disposition are expected to total $9.5 million which will permit excess funds to be directed toward debt repayment[(2)]. Petrus is committed to maintaining its financial flexibility and the Company will determine subsequent quarter capital spending as the year progresses. For the coming year there is significant optionality in the number, the commodity composition and the location of drilling opportunities. Management anticipates that the 2020 capital plan will be funded by funds flow, and will continue to systematically reduce debt each quarter by approximately $1 to $2 million. The objectives of the 2020 capital plan are to reduce debt, maintain or grow production, grow funds flow per share and increase the Company's liquids weighting. Petrus continues its efforts to divest additional non-core assets to improve the balance sheet and also continues its discussions with its lenders in order to extend the upcoming 2020 debt maturity dates.

[(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 - Presentation" in the Management's Discussion & Analysis attached hereto.

PRESIDENT'S MESSAGE

The energy industry had another very challenging year in 2019. At the beginning of the year, we set out with the primary goal of strengthening our balance sheet, using excess funds flow to reduce debt by approximately $1 - $2 million per quarter, while targeting to maintain our annual funds flow of $33 million. In order to accomplish this systematic deleveraging, the Petrus team embarked on a very disciplined capital program targeting maximum efficiency of capital deployment and operating performance.

During the year we were able to exceed our goal, reducing net debt by $15.5 million with annual funds flow of $33.6 million. Our 2019 capital program of $18.1 million was the lowest annual total in the Company's history. The development plan targeted exclusively Cardium oil locations in Ferrier. This drilling program surpassed 2018, becoming the most efficient in the Company's history in terms of rate of return and payout. We were able to add new production at a cost of approximately $14,300/boed, which represents the average of the three previous years. At $13.31/boe, our PDP FD&A cost was one of the lowest finding costs we have achieved. For the fourth year in a row we have reduced our annual operating costs which in 2019 were $4.25/boe. And in addition to reducing net debt, the Company has also worked to reduce its abandonment and reclamation obligations. With the completion of the Foothills sale our undiscounted, uninflated ARO will reduce by $7.5 million (18%) to a total of approximately $34 million. This will put our ARO per quarterly boe of production in the top third of our peers and less than half the average of the group.

In 2020, we will continue to improve our balance sheet by drilling Ferrier Cardium oil locations, increasing our liquids weighting, monetizing non-core assets, reducing operating costs and continuing to deploy capital as efficiently as possible. With pricing volatility, it is paramount that we remain disciplined and adaptable in our approach. We are committed to reducing our debt on a systematic basis, targeting debt repayment of $1 to $2 million per quarter. By improving our balance sheet and continuing to improve our project execution, Petrus will not only be able to withstand further pricing volatility but also have the flexibility to increase drilling investment should pricing allow.

NKorchinski

Neil Korchinski
President, Chief Executive Officer and Director

RESERVES

Petrus' 2019 year end reserves were evaluated by independent reserves evaluator, Sproule Associates Limited, 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, 2019 ("2019 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, 2019, which will be available under the Company's profile on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

Petrus has a reserves committee, comprised of independent board members, that reviews the qualifications and appointment of the independent reserves evaluator. 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 evaluator 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 2019 Sproule Report.

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

As at December 31, 2019	**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	46,105	1,248	2,723	11,655	143,061	151,543	138,707
Proved Non-Producing	18,202	5	91	3,129	15,255	11,428	9,032
Proved Undeveloped	56,397	1,260	4,763	15,422	204,442	138,197	95,400
Total Proved	**120,703**	**2,513**	**7,576**	**30,207**	**362,758**	**301,168**	**243,140**
Proved + Probable Producing	59,232	1,671	3,414	14,957	212,786	194,341	167,735
Total Probable	**62,672**	**2,477**	**3,773**	**16,696**	**306,799**	**207,302**	**149,307**
Total Proved Plus Probable	**183,376**	**4,990**	**11,350**	**46,902**	**669,557**	**508,470**	**392,446**

(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 0%, 5% and 10%, respectively and is presented before tax and based on Sproule's pricing assumptions.
(3)Total company interest reserve volumes 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 2019, Petrus' development program generated Proved Developed Producing ("PDP") reserve volume additions of 1.3 mmboe which were comprised of 45% light oil. The Company produced 3.0 mmboe during 2019 and ended the year with 11.7 mmboe of PDP reserve volume (34% oil and liquids).

Petrus ended 2019 with $147.7 million, $243.1 million and $392.4 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 2019 Sproule Report. In 2019, the Company realized Finding and Development ("FD&A")[(1)(2)] costs of $13.31/boe for PDP reserves.

Based on the 2019 Sproule Report, the Company's PDP reserve value before-tax, discounted at 10% is $2.80 per share. On the same basis, the P+P reserve value is $7.93 per share.

(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.

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. The following table provides a summary of the Company's FDC as set forth in the 2019 Sproule Report:

Future Development Cost ($000s)	**Total Proved**	**Total Proved + Probable**
2020	41,019	54,452
2021	72,106	135,558
2022	50,186	57,561
2023	5,782	15,147
Thereafter	4,934	4,934
Total FDC, Undiscounted	**174,027**	**267,652**
Total FDC, Discounted at 10%	**149,383**	**229,770**

PERFORMANCE RATIOS

The following table highlights annual performance ratios for the Company from 2015 to 2019:

	December 31, 2019	**December 31, 2018**	**December 31, 2017**	**December 31, 2016**	**December 31, 2015**
Proved Producing					
FD&A ($/boe) [(1)(2)]	**13.31**	37.76	13.05	(0.43)	23.18
F&D ($/boe) [(1)(2)]	**12.81**	42.27	11.57	9.89	29.80
Reserve Life Index (yr) [(1)]	**3.8**	4.6	4.1	4.4	5.2
Reserve Replacement Ratio [(1)]	**0.4**	0.2	1.6	0.4	0.7
FD&A Recycle Ratio [(1)]	**1.2**	0.4	1.1	(24.8)	0.7
Proved Developed					
FD&A ($/boe) [(1)(2)]	**12.49**	11.34	16.74	(0.23)	39.85
F&D ($/boe) [(1)(2)]	**12.03**	11.55	14.62	7.69	65.74
Reserve Life Index (yr) [(1)]	**4.8**	5.6	4.5	5.3	5.8
Reserve Replacement Ratio [(1)]	**0.5**	0.6	1.2	0.7	0.4
FD&A Recycle Ratio [(1)]	**1.3**	1.4	0.9	(46.3)	0.4
Total Proved					
FD&A ($/boe) [(1)(2)]	**1.09**	8.73	14.33	(15.78)	16.77
F&D ($/boe) [(1)(2)]	**(6.83)**	8.16	12.03	2.46	21.02
Reserve Life Index (yr) [(1)]	**9.9**	11.1	8.0	9.8	10.9
Reserve Replacement Ratio [(1)]	**0.3**	1.3	1.1	0.5	2.9
FD&A Recycle Ratio [(1)]	**14.4**	1.8	1.0	(0.7)	0.9
Future Development Cost ($000s)	**174,027**	194,757	182,086	201,556	223,409
Total Proved + Probable					
FD&A ($/boe) [(1)(2)]	**(7.32)**	6.49	14.87	350.09	15.40
F&D ($/boe) [(1)(2)]	**190.21**	5.15	17.28	(8.06)	19.01
Reserve Life Index (yr) [(1)]	**15.4**	17.1	12.3	14.6	16.4
Reserve Replacement Ratio [(1)]	**—**	1.5	1.7	(0.1)	3.7
FD&A Recycle Ratio [(1)]	**(2.1)**	2.4	1.0	—	1.0
Future Development Cost ($000s)	**267,652**	290,876	283,030	269,144	325,325

[(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.

NET ASSET VALUE

The following table shows the Company's Net Asset Value ("NAV"), calculated using Sproule's December 31, 2019 price forecast:

As at December 31, 2019 ($000s except per share)	Proved Developed Producing	Total Proved	Proved + Probable
Present Value Reserves, before tax (discounted at 10%) [1]	138,707	243,140	392,446
Undeveloped Land Value [2]	36,116	36,116	36,116
Net Debt [3]	(123,744)	(123,744)	(123,744)
Net Asset Value	**51,079**	**155,512**	**304,818**
Estimated Net Asset Value per Share	**$1.03**	**$3.14**	**$6.16**

(1) *Based on the 2019 Sproule Report, using the forecast future prices and costs.*
(2) *Based on the exploration and evaluation assets as per the Company's December 31, 2019 audited consolidated financial statements.*
(3) *See "Non-GAAP Financial Measures" in the Management's Discussion & Analysis attached hereto.*

MANAGEMENT'S DISCUSSION & ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of the financial and operating results of Petrus Resources Ltd. ("Petrus" or the "Company") as at and for the three and twelve months ended December 31, 2019. This MD&A is dated February 18, 2020 and should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2019 and 2018. The Company's audited 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, 2019	Twelve months ended Dec. 31, 2018	Three months ended Dec. 31, 2019	Three months ended Sept. 30, 2019	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019
Average Production						
Natural gas (mcf/d)	32,032	37,101	32,641	30,998	32,350	32,145
Oil (bbl/d)	1,616	1,402	1,834	1,247	1,679	1,704
NGLs (bbl/d)	1,351	1,433	1,018	1,372	1,576	1,444
Total (boe/d)	**8,306**	**9,019**	**8,292**	**7,785**	**8,647**	**8,505**
Total (boe)	**3,031,659**	**3,292,828**	**762,874**	**716,220**	**786,819**	**765,488**
Light oil weighting	19%	16%	22%	16%	19%	20%
Realized Prices						
Natural gas ($/mcf)	1.89	1.73	2.65	1.12	1.30	2.44
Oil ($/bbl)	64.11	69.74	65.16	65.64	70.96	55.10
NGLs ($/bbl)	22.13	40.50	20.62	11.49	19.91	36.02
Total realized price ($/boe)	**23.35**	**24.40**	**27.39**	**16.99**	**22.29**	**26.36**
Royalty income	0.20	0.12	0.13	0.48	0.15	0.06
Royalty expense	(2.35)	(3.54)	(2.91)	(1.65)	(1.72)	(3.08)
Net oil and natural gas revenue ($/boe)	**21.20**	**20.98**	**24.61**	**15.82**	**20.72**	**23.34**
Operating expense	(4.25)	(4.75)	(4.47)	(4.44)	(4.33)	(3.76)
Transportation expense	(1.26)	(1.15)	(1.30)	(1.25)	(1.22)	(1.27)
Operating netback[1] ($/boe)	**15.69**	**15.08**	**18.84**	**10.13**	**15.17**	**18.31**
Realized gain (loss) on derivatives ($/boe)	(0.44)	(0.90)	(1.86)	0.50	(1.02)	0.67
Other income	0.03	0.13	—	0.03	0.10	—
General & administrative expense	(1.20)	(1.57)	(1.91)	(1.08)	(0.67)	(1.15)
Cash finance expense	(2.72)	(2.51)	(2.54)	(3.11)	(2.70)	(2.54)
Decommissioning expenditures	(0.28)	(0.14)	(0.41)	(0.29)	(0.24)	(0.18)
Funds flow & corporate netback[1][2] ($/boe)	**11.08**	**10.09**	**12.12**	**6.18**	**10.64**	**15.11**

FINANCIAL (000s except $ per share)	Twelve months ended Dec. 31, 2019	Twelve months ended Dec. 31, 2018	Three months ended Dec. 31, 2019	Three months ended Sept. 30, 2019	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019
Oil and natural gas revenue	71,398	80,716	20,998	12,517	17,652	20,231
Net income (loss)	(42,176)	(3,284)	(3,332)	(29,569)	2,863	(12,138)
Net income (loss) per share						
Basic	(0.85)	(0.07)	(0.06)	(0.60)	0.06	(0.25)
Fully diluted	(0.85)	(0.07)	(0.06)	(0.60)	0.06	(0.25)
Funds flow	33,625	33,184	9,260	4,427	8,366	11,573
Funds flow per share						
Basic	0.68	0.67	0.19	0.09	0.17	0.23
Fully diluted	0.68	0.67	0.19	0.09	0.17	0.23
Capital expenditures	18,073	24,098	4,351	2,734	2,505	8,483
Net dispositions	651	448	—	651	—	—
Weighted average shares outstanding						
Basic	49,472	49,492	49,469	49,469	49,469	49,483
Fully diluted	49,472	49,492	49,469	49,469	49,469	49,483
As at year end						
Common shares outstanding						
Basic	49,469	49,492	49,469	49,469	49,469	49,469
Fully diluted	49,469	49,492	49,469	49,469	49,469	49,469
Total assets	289,225	341,820	289,225	296,367	328,912	336,974
Non-current liabilities	42,346	171,646	42,346	82,650	81,249	176,093
Net debt[1]	123,744	139,214	123,744	128,553	130,619	136,382

[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 comparable additional GAAP measure. Petrus analyzes these measures on an absolute value and per unit basis.*

OPERATIONS UPDATE

Fourth quarter average production by area was as follows:

For the three months ended December 31, 2019	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	25,149	1,745	5,747	32,641
Oil (bbl/d)	1,357	135	342	1,834
NGLs (bbl/d)	852	8	158	1,018
Total (boe/d)	**6,401**	**433**	**1,458**	**8,292**

Fourth quarter average production was 8,292 boe/d in 2019 compared to 7,785 boe/d in the third quarter of 2019. During the second half of 2019 the Company drilled 7 gross (1.6 net) Cardium light oil wells. Average production from the 1.6 net wells over the fourth quarter, net to Petrus, was approximately 560 bbl/d of oil and approximately 1,600 mcf/d of natural gas. The Company's development plan is strategically balanced between increasing its Cardium light oil weighting in the Ferrier area and continuing to improve its balance sheet. In 2019, Petrus drilled 10 gross (3.1 net) Cardium light oil wells, increased its light oil weighting 24% from the beginning of 2018 and reduced net debt[1] $15.5 million. Since December 31, 2017 Petrus has repaid $24.3 million (16%) of net debt.

The average benchmark natural gas price in Canada (AECO 5A monthly index) was $2.35/GJ in the fourth quarter, a significant increase from the third quarter 2019 average price of $0.87/GJ. Petrus anticipates the impacts of TC Energy Corporation's previously announced Temporary Service Protocol, continued expansion of the NGTL system in 2020 and 2021 and current Alberta natural gas storage levels will all continue to support Canadian natural gas prices[2].

Petrus' Board of Directors has approved a first quarter 2020 capital budget of $9.0 million to drill 2 (2.0 net) Cardium light oil wells in the Ferrier area. First quarter funds flow combined with proceeds from the previously announced non-core asset disposition are expected to total $9.5 million which will provide excess funds to be directed toward debt repayment. Management anticipates that the 2020 capital plan will be funded by funds flow, and will continue to systematically reduce debt each quarter by approximately $1 to $2 million. The objectives of the 2020 capital plan are to reduce debt, maintain or grow production, grow funds flow per share and increase the Company's liquids weighting [2].

Petrus believes it is unique in the junior E&P company space, as few gas-weighted companies are able to repay debt and grow production and funds flow all within funds from operations. Over the past four years, Petrus has dramatically strengthened its business in order to improve its sustainability as well as mitigate commodity price risk. Operating costs have been reduced by 68% since 2012 and management believes Petrus' total cash costs of $9.43/boe are consistently one of the lowest amongst its peers. The Company intends to continue its disciplined focus on balance sheet improvement and capital deployment in 2020[2].

CREDIT FACILITY UPDATE

In November 2019, Petrus completed its semi-annual revolving credit facility ("RCF") review where its $100 million facility was reconfirmed. On December 31, 2019 Petrus reduced its borrowings under the RCF by $2 million and expects to make another $2 million repayment on March 31, 2020. The Company's RCF maturity date is May 31, 2020 which was set prior to the Company's term loan maturity date of October 8, 2020 ("Term Loan"), due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF. The borrowings under the RCF and Term Loan are classified as current liabilities in the December 31, 2019 consolidated financial statements which has no impact on the debt covenants and the Company remains, and expects to continue to be, in compliance with each of its covenants. Management is actively engaged in discussions with its lenders in order to extend the upcoming 2020 maturity dates. The Company continues its efforts to divest certain non-core assets to improve its balance sheet.

NON-CORE ASSET DISPOSITION

In December 2019, Petrus entered into an agreement for the sale of its oil and natural gas interests in the Foothills area of Alberta to an arm's length private company for total consideration of $1.8 million, subject to regulatory approvals and customary closing conditions and adjustments (the "Disposition"). The Disposition has an effective date of November 1, 2019 and is expected to close in the first quarter of 2020. In the fourth quarter of 2019, production in the Company's Foothills area averaged approximately 433 boe/d (67% natural gas), which comprised 5% of Petrus' total production. The Foothills assets include facility interests and 35,127 net acres of undeveloped land. The Disposition is expected to reduce the Company's indebtedness, operating expenses and future abandonment liabilities. It is expected to reduce Petrus' undiscounted, uninflated decommissioning obligation by $7.5 million or 18%. The cash proceeds from the Disposition will be used to reduce the borrowings under the Company's RCF.

[1]*Refer to "Non-GAAP Financial Measures."*
[2]*Refer to "Advisories - Forward-Looking Statements."*

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Twelve months ended Dec. 31, 2019	Twelve months ended Dec. 31, 2018	Three months ended Dec. 31, 2019	Three months ended Sept. 30, 2019	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019
Average production						
Natural gas (mcf/d)	32,032	37,101	32,641	30,998	32,350	32,145
Oil (bbl/d)	1,616	1,402	1,834	1,247	1,679	1,704
NGLs (bbl/d)	1,351	1,433	1,018	1,372	1,576	1,444
Total (boe/d)	**8,306**	**9,019**	**8,292**	**7,785**	**8,647**	**8,505**
Total (boe)	**3,031,659**	**3,292,828**	**762,874**	**716,220**	**786,819**	**765,488**
Revenue ($000s)						
Natural gas	22,052	23,453	7,970	3,192	3,839	7,051
Oil	37,815	35,684	10,995	7,529	10,841	8,450
NGLs	10,917	21,186	1,931	1,450	2,855	4,681
Royalty revenue	614	393	102	346	117	49
Oil and natural gas revenue	**71,398**	**80,716**	**20,998**	**12,517**	**17,652**	20,231
Average realized prices						
Natural gas ($/mcf)	1.89	1.73	2.65	1.12	1.30	2.44
Oil ($/bbl)	64.11	69.74	65.16	65.64	70.96	55.10
NGLs ($/bbl)	22.13	40.50	20.62	11.49	19.91	36.02
Total realized price ($/boe)	23.35	24.40	27.39	16.99	22.29	26.36
Hedging gain (loss) ($/boe)	(0.44)	(0.90)	(1.86)	0.50	(1.02)	0.67
Total price including hedging ($/boe)	**22.91**	**23.50**	**25.53**	**17.49**	**21.27**	27.03

Average benchmark prices	Twelve months ended Dec. 31, 2019	Twelve months ended Dec. 31, 2018	Three months ended Dec. 31, 2019	Three months ended Sept. 30, 2019	Three months ended Jun. 30, 2019	Three months ended Mar. 31, 2019
Natural gas						
AECO 5A (C$/GJ)	1.67	1.42	2.35	0.87	0.98	2.48
AECO 7A (C$/GJ)	1.54	1.45	2.21	0.99	1.11	1.84
Crude oil						
Mixed Sweet Blend Edm (C$/bbl)	69.03	69.13	66.81	69.21	72.66	67.46
Natural gas liquids						
Propane Conway (US$/bbl)	20.34	30.71	19.78	15.56	20.60	24.40
Butane Edmonton (C$/bbl)	21.70	35.07	36.96	24.78	24.43	5.91
Foreign exchange						
US$/C$	0.75	0.77	0.76	0.76	0.75	0.75

FUNDS FLOW AND NET INCOME (LOSS)

Petrus generated funds flow of $9.3 million in the fourth quarter of 2019 compared to $5.0 million in 2018. The 68% increase is due to higher commodity prices in the fourth quarter of 2019. In the fourth quarter Petrus' total realized price was $27.39/boe compared to $21.91/boe in the prior year.

For the year ended December 31, 2019, Petrus generated funds flow of $33.6 million compared to $33.2 million in the prior year. The 1% decrease is due to lower production and lower commodity prices during the 12 month period.

Petrus reported a net loss of $3.2 million in the fourth quarter of 2019, compared to net income of $21.1 million in the fourth quarter of 2018. The net income in the fourth quarter of 2018 compared to the net loss in the current year is primarily due to the accounting for unrealized hedging on financial derivatives. During the fourth quarter of 2019, the Company recognized an unrealized loss of $3.7 million whereas during the fourth quarter of 2018 a $25.4 million unrealized gain was recorded, which had a material impact on net income in the fourth quarter of 2018. The differences are due to changes in commodity prices at December 31 of the respective years.

On a twelve month basis, the Company generated a net loss of $42.2 million in 2019 compared to a net loss of $3.3 million in 2018. The increase is primarily due to the $24.7 million impairment expense recorded during the third quarter of 2019 on the Company's non-core Foothills and Central Alberta assets as well as the unrealized hedging loss of $11.3 million realized in 2019 (unrealized hedging gain of $7.5 million in 2018).

($000s except per share)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Funds flow	**9,260**	**5,030**	**33,625**	**33,184**
Funds flow per share - basic	0.19	0.10	0.68	0.67
Funds flow per share - fully diluted	0.19	0.10	0.68	0.67
Net income (loss)	**(3,176)**	**21,063**	**(42,176)**	**(3,284)**
Net income (loss) per share - basic	(0.06)	0.43	(0.85)	(0.07)
Net income (loss) per share - fully diluted	(0.06)	0.43	(0.85)	(0.07)
Common shares outstanding (000s)				
Basic	49,469	49,492	49,469	49,492
Fully diluted	49,469	49,492	49,469	49,492
Weighted average shares outstanding (000s)				
Basic	49,469	49,492	49,472	49,492
Fully diluted	49,469	49,492	49,472	49,492

OIL AND NATURAL GAS REVENUE

Fourth quarter average production in 2019 was 8,292 boe/d (22% light oil), 5% higher than 2018 (7,934 boe/d; 17% light oil). Fourth quarter oil and natural gas revenue in 2019 was $21.0 million compared to $16.1 million in 2018. The 30% increase is due to higher commodity prices in addition to 5% higher production.

Annual average production in 2019 was 8,306 boe/d (19% light oil), 8% lower than 2018 (9,019 boe/d; 16% light oil). Total oil and natural gas revenue decreased from $80.7 million for the year ended December 31, 2018 to $71.4 million in 2019 due to 8% lower production.

The following table provides a breakdown of composition of the Company's production volume by product:

Production Volume by Product (%)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Natural gas	**66%**	64%	**64%**	68%
Crude oil and condensate	**22%**	17%	**20%**	16%
Natural gas liquids	**12%**	19%	**16%**	16%
Total commodity sales from production	**100%**	**100%**	**100%**	**100%**

The following table presents oil and natural gas revenue by product and the change from the prior comparative periods:

Oil and Natural Gas Revenue ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	% Change	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018	% Change
Natural gas	**7,970**	5,473	46 %	**22,052**	23,453	(6)%
Crude oil and condensate	**10,995**	6,522	69 %	**37,815**	35,684	6 %
Natural gas liquids	**1,931**	3,993	(52)%	**10,917**	21,186	(48)%
Royalty income	**102**	76	34 %	**614**	393	56 %
Total oil and natural gas revenue	**20,998**	**16,064**	**31 %**	**71,398**	**80,716**	**(12)%**

The following table provides the average benchmark the Company's average realized commodity prices:

	Three months ended December 31, 2019	Three months ended December 31, 2018	% Change	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018	% Change
Average benchmark prices						
Natural gas						
AECO 5A (C$/GJ)	**2.35**	1.47	60 %	**1.67**	1.42	18 %
AECO 7A (C$/GJ)	**2.21**	1.80	23 %	**1.54**	1.45	6 %
Crude oil						
Mixed Sweet Blend Edm (C$/bbl)	**66.81**	48.12	39 %	**69.03**	69.13	— %
Natural gas liquids						
Propane Conway (US$/bbl)	**19.78**	29.82	(34)%	**20.34**	30.71	(34)%
Butane Edmonton (C$/bbl)	**36.96**	18.06	105 %	**21.70**	35.07	(38)%
Average realized prices						
Natural gas ($/mcf)	**2.65**	1.95	36 %	**1.89**	1.73	9 %
Oil ($/bbl)	**65.16**	52.26	25 %	**64.11**	69.74	(8)%
NGLs ($/bbl)	**20.62**	29.01	(29)%	**22.13**	40.50	(45)%
Total average realized price	**27.39**	**21.91**	**25 %**	**23.35**	**24.40**	**(4)%**

Natural gas

Natural gas revenue for the year ended December 31, 2019 was $22.1 million which accounted for 31% of oil and natural gas revenue, compared to revenue of $23.5 million which accounted for 29% in 2018. The decrease is due to 14% lower natural gas production.

Fourth quarter 2019 average realized natural gas price was $2.65/mcf, compared to $1.95/mcf in 2018 (36% increase). Fourth quarter 2019 natural gas revenue was $8.0 million which accounted for 38% of oil and natural gas revenue, compared to revenue of $5.5 million accounting for 34% in 2018. Fourth quarter natural gas revenue increased from 2018 due to higher natural gas production and 60% higher natural gas pricing.

Crude oil and condensate

Oil and condensate revenue for the fourth quarter of 2019 was $11.0 million accounted for approximately 53% of oil and natural gas revenue, compared to revenue of $6.5 million, accounting for 41% in 2018.

The average realized price of Petrus' light oil and condensate was $65.16/bbl for the fourth quarter of 2019 compared to $52.26/bbl for the prior year. The increase of 25% is attributable to the increase in commodity price.

Oil and condensate revenue for the year ended December 31, 2019 was $37.8 million, which accounted for 53% of oil and natural gas revenue, compared to revenue of $35.7 million, which accounted for 44% in 2018.

The average realized price of Petrus' light oil and condensate was $64.11/bbl for 2019 compared to $69.74/bbl for the prior year. The decrease of 8% is attributable to pricing differentials.

Natural gas liquids (NGLs)

The Company's NGL production mix consists of ethane, propane, butane and pentane. The pricing received for NGL production is based on annual contracts effective the first of April each year. The contract prices are based on the product mix, the fractionation process required and the demand for fractionation facilities. In the fourth quarter of 2019, the Company's realized NGL price averaged $20.62/bbl, compared to $29.01/bbl in the prior year. The 29% decrease is attributed to lower contract prices for the NGL byproducts. Fourth quarter market pricing for propane at Conway decreased 34% from the prior year. Petrus' butane production is priced as a function of WTI (oil) which also decreased in the fourth quarter compared to the prior year. In 2019, the Company's realized NGL price averaged $22.13/bbl compared to $40.50/bbl in 2018. Similar to the fourth quarter, the 45% decrease in realized pricing is attributed to lower market pricing for propane at Conway and WTI (oil).

Petrus' ownership and control of critical processing facilities enables the Company to respond and continually optimize its production revenue streams. To improve operating netback, during the third quarter of 2019, Petrus ceased sending certain natural gas for additional third party deepcut processing to extract additional NGLs. This resulted in lower NGL production volume, however, the heating value of natural gas sales increased and processing fees decreased. Petrus continues to monitor NGL market pricing and is able to modify its operations accordingly.

Fourth quarter 2019 NGL revenue was $1.9 million and accounted for 9% of oil and natural gas revenue, compared to revenue of $4.0 million accounting for 25% in 2018.

NGL revenue for the year ended December 31, 2019 was $10.9 million and accounted for 15% of oil and natural gas revenue, compared to revenue of $21.2 million, accounting for 26% in 2018.

ROYALTY EXPENSE

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company’s royalty expense (net of royalty allowances and incentives) for the periods shown:

Royalty Expense ($000s)	**Three months ended December 31, 2019**	**Three months ended December 31, 2018**	**Twelve months ended December 31, 2019**	**Twelve months ended December 31, 2018**
Crown	**1,232**	1,086	**3,298**	4,279
Percent of production revenue	**6%**	7%	**5%**	5%
Gross overriding	**986**	1,350	**3,816**	7,359
Total	**2,218**	**2,436**	**7,114**	**11,638**

Fourth quarter royalty expense decreased from $2.4 million in 2018 to $2.2 million in 2019 primarily due to lower NGL revenue and favorable royalty rates on the new wells that came on production. For the year, total royalty expense decreased from $11.6 million in 2018 to $7.1 million in 2019. The decrease is due to lower production and favorable royalty allowances.

Fourth quarter gross overriding royalties decreased from $1.4 million in 2018 to $1.0 million in 2019, due to lower light oil and NGL prices. Gross overriding royalties for the year decreased from $7.4 million in 2018 to $3.8 million in 2019, due to the decrease in production and lower NGL prices.

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, 2019**	**Three months ended December 31, 2018**	**Twelve months ended December 31, 2019**	**Twelve months ended December 31, 2018**
Realized hedging loss	**(1,417)**	(573)	**(1,344)**	(2,961)
Unrealized hedging gain (loss)	**(3,668)**	25,370	**(11,273)**	7,510
Net gain (loss) on derivatives	**(5,085)**	**24,797**	**(12,617)**	**4,549**

In the fourth quarter, the Company recognized a realized hedging loss of $1.4 million in 2019, compared to a $0.6 million loss in 2018. The realized losses are due to higher gas commodity prices (relative to the respective contracts outstanding). The realized loss in the fourth quarter of 2019 decreased the Company's total realized price by $1.86/boe, compared to $0.79/boe in 2018.

For the year, the Company recognized a realized hedging loss of $1.3 million in 2019, compared to the $3.0 million loss realized in 2018. The realized losses are due to higher commodity prices (relative to the respective contracts outstanding). The realized losses decreased Petrus' total realized price by $0.44 and $0.90 in 2019 and 2018, respectively.

The fourth quarter unrealized hedging loss of $3.7 million represents the change in the unrealized net risk management position during the quarter. The unrealized hedging loss of $11.3 million for the year ended December 31, 2019 represents the change in the unrealized risk management net asset position during 2019. These changes are a result of both the realization of hedging gains/losses during the year, changes related to contracts entered into during the year as well as changes to commodity prices.

The Company's risk management contracts provide protection from significant changes in crude oil and natural gas commodity prices for 2019, 2020 and 2021. The Company endeavors to hedge approximately half of its forecast production for the following year, and approximately 30% 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 11 of the Company's consolidated financial statements as at and for the year ended December 31, 2019. The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The average volume of oil hedged for 2020 (1,075 bbl/d) represents 59% of fourth quarter 2019 average oil production. The 12,333 GJ/day average natural gas hedged for 2020 represents 36% of fourth quarter 2019 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:

	2020					2021				
	Q1	Q2	Q3	Q4	Avg.[1]	Q1	Q2	Q3	Q4	Avg.[1]
Oil hedged (bbl/d)	1,450	1,150	950	750	**1,075**	500	300	300	300	**350**
Avg. WTI cap price ($C/bbl)	73.23	76.33	76.71	75.12	**75.16**	72.83	74.02	72.80	72.80	**73.07**
Avg. WTI floor price ($C/bbl)	73.23	76.33	76.71	75.12	**75.16**	72.83	74.02	72.80	72.80	**73.07**
Natural gas hedged (GJ/d)	15,500	12,500	12,500	8,833	**12,333**	7,000	4,000	4,000	1,333	**4,083**
Avg. AECO 7A cap price ($C/GJ)	1.76	1.52	1.52	1.59	**1.61**	1.63	1.60	1.60	1.60	**1.61**
Avg. AECO 7A floor price ($C/GJ)	1.76	1.52	1.52	1.59	**1.61**	1.63	1.60	1.60	1.60	**1.61**

[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 ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Fixed and variable operating expense	**2,655**	2,961	**10,668**	13,084
Processing, gathering and compression charges	**980**	1,124	**3,167**	3,602
Total gross operating expense	**3,635**	**4,085**	**13,835**	**16,686**
Overhead recoveries	**(228)**	(234)	**(962)**	(1,034)
Total net operating expense	**3,407**	**3,851**	**12,873**	**15,652**
Operating expense, net ($/boe)	**4.47**	**5.28**	**4.25**	**4.75**

Fourth quarter net operating expense totaled $3.4 million in 2019, a 12% decrease from $3.9 million in 2018. On a per boe basis it was 15% lower at $4.47/boe in 2019 compared to $5.28/boe in 2018. The decreases are attributable to decreased activity related to well workover projects.

For the year ended December 31, 2019, net operating expense totaled $12.9 million, an 18% decrease from the $15.7 million in 2018. The decrease is attributable to 8% lower production and decreased activity related to facility and well workover projects. On a per boe basis it was $4.25/boe for the year ended December 31, 2019, 11% lower than the $4.75/boe in 2018. The decrease is related to lower non-routine expenditures.

TRANSPORTATION EXPENSE

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

Transportation Expense ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Transportation expense	**991**	855	**3,814**	3,789
Transportation expense ($/boe)	**1.30**	1.17	**1.26**	1.15

Petrus pays commodity and demand charges for transporting its gas on pipeline systems. The Company also incurs trucking costs on the portion of its oil and natural gas liquids production that is not pipeline connected. Fourth quarter 2019 transportation expense was $1.0 million or $1.30/boe compared to $0.9 million or $1.17/boe in 2018. The increase in transportation expense is attributed to increased tolls on midstream pipelines, increased NGL volume transported via truck and 5% higher production. For the year ended December 31, 2019, transportation expense totaled $3.8 million, or $1.26/boe, compared to $3.8 million or $1.15/boe in 2018. The increases are attributed to increased trucking costs and 14% decreased production (on a per boe basis).

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 ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Personnel, consultants and directors	**1,139**	1,248	**3,875**	4,610
Administrative expenses	**613**	680	**1,657**	2,588
Regulatory and professional expenses	**218**	320	**685**	1,031
Gross general and administrative expense	**1,970**	**2,248**	**6,217**	**8,229**
Capitalized general and administrative expense	(439)	(487)	(1,506)	(1,718)
Overhead recoveries	(72)	(696)	(1,067)	(1,327)
General and administrative expense	**1,459**	**1,065**	**3,644**	**5,184**
General and administrative expense ($/boe)	**1.91**	**1.46**	**1.20**	**1.57**

Fourth quarter gross G&A expense was 12% lower than the prior year ($2.0 million in 2019 compared to $2.2 million in 2018) which is attributed to lower office rent which is now accounted for as finance and depreciation expense under IFRS 16 as well as lower office expenses and staffing costs due to fewer personnel. Fourth quarter 2019 G&A expense (net) was $1.5 million or $1.91/boe, compared to $1.1 million or $1.46/boe in 2018. The increases in 2019 on a net basis are attributed to lower capitalized G&A and overhead recoveries due to lower capital activity.

For the year ended December 31, 2019, gross G&A expense was $6.2 million compared to $8.2 million in 2018 which represents a 24% decrease. Annual G&A expense (net) in 2019 was $3.6 million or $1.20/boe compared to $5.2 million or $1.57/boe in 2018 (24% decrease on a per boe basis despite 8% lower annual production). The decreases are attributed to lower office rent (IFRS 16), and fewer personnel resulting in lower office and personnel expenses.

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, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Gross share-based compensation expense	**125**	329	**529**	858
Capitalized share-based compensation expense	**34**	(70)	**(128)**	(282)
Share-based compensation expense	**159**	**259**	**401**	**576**

Fourth quarter net share-based compensation expense was $0.2 million in 2019, which is 39% lower than the $0.3 million in 2018. For the year ended December 31, 2019, net share-based compensation expense was $0.4 million, which is 30% lower than the $0.6 million in 2018.

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, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Interest expense	**1,939**	2,370	**8,241**	8,273
Deferred financing costs	**121**	174	**495**	637
Accretion on decommissioning obligations	**176**	224	**777**	887
Total finance expense	**2,236**	**2,768**	**9,513**	**9,797**

Fourth quarter total finance expense was $2.2 million in 2019, comprised of $0.2 million of non-cash accretion of its decommissioning obligations, $1.9 million of cash interest expense and $0.1 million of deferred financing fee amortization, both of which are related to the RCF and Term Loan. In the fourth quarter of 2018, the Company incurred total finance expense of $2.8 million, comprised of $0.2 million in non-cash accretion of its decommissioning obligation, $2.4 million cash interest expense and $0.2 million of deferred financing fee amortization. The decrease in total finance expense from the prior year is due to lower RCF balance.

The Company incurred total finance expense of $9.5 million for the year ended December 31, 2019, which is lower than the $9.8 million for 2018. The decrease is due to the lower RCF balance outstanding.

DEPLETION AND DEPRECIATION

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

Depletion and Depreciation Expense ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Depletion and depreciation expense	**8,735**	8,679	**36,564**	40,423
Depletion and depreciation expense ($/boe)	**11.45**	11.89	**12.06**	12.28

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.

Fourth quarter depletion and depreciation expense in 2019 was $8.7 million or $11.45/boe, compared to $8.7 million or $11.89/boe in 2018. For the year ended December 31, 2019, the Company recorded $36.6 million or $12.06/boe, compared to $40.4 million or $12.28/boe in 2018. The decreases in depletion and depreciation expense per boe are attributed to the impairment recorded in the third quarter of 2019.

IMPAIRMENT

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

Impairment ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Impairment	**—**	—	**24,655**	—
Total	**—**	**—**	**24,655**	**—**

Petrus has certain CGUs that are not core to the Company. As such, a sales process has been in place 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, Petrus recognized an impairment loss of $24.7 million during the year ended December 31, 2019 (nil in 2018).

SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of 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, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Weighted average Common Shares outstanding				
Basic	**49,469**	49,492	**49,472**	49,492
Fully diluted	**49,469**	49,492	**49,472**	49,492
Common shares outstanding				
Basic	**49,469**	49,492	**49,469**	49,492
Fully diluted	**49,469**	49,492	**49,469**	49,492
Stock options outstanding	**2,362**	3,083	**2,362**	3,083

At December 31, 2019, the Company had 49,469,358 common shares and 2,361,958 stock options outstanding.

The Company issued 1,386,357 stock options during the year ended December 31, 2019:

(a) 390,000 stock options were issued on March 22, 2019 at an exercise price of $0.45.
(b) 300,000 stock options were issued on June 10, 2019 at an exercise price of $0.32.
(c) 696,357 stock options were issued on December 27, 2019 at an exercise price of $0.26.

The Company has a deferred share unit plan in place whereby it may issue deferred share units ("DSUs") to directors of the Company. At December 31, 2019, 1,177,510 (December 31, 2018 – 382,796) DSUs were issued and outstanding. Each DSU entitles the participants to receive, at the Company's discretion, either Common Shares or cash equivalent to the number of DSUs multiplied by the current trading price of the equivalent number of common shares. All DSUs vest and become payable upon retirement of the director.

LIQUIDITY AND CAPITAL RESOURCES

Petrus has two debt instruments outstanding. The first is a reserve-based, senior secured revolving credit facility with a syndicate of lenders, which is the RCF. The second is the Term Loan.

(a) Revolving Credit Facility

At December 31, 2019, the RCF was comprised of a $20 million operating facility and a $78 million syndicated term-out facility. Lender consent is required for borrowings exceeding $93 million. The syndicated term-out facility and the amount of borrowing that requires lender consent will be reduced by $2 million on March 31, 2020. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company. The RCF's maturity date is May 31, 2020 which was set prior to the Term Loan maturity of October 8, 2020 due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF.

At December 31, 2019, the Company had a $0.7 million letter of credit outstanding against the RCF (December 31, 2018 – $0.7 million) and had drawn $92.3 million against the RCF (December 31, 2018 – $97.0 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, 2020. In the event that the lenders reduce the borrowing base below the amount drawn at the time of redetermination, the Company has 60 days to eliminate any shortfall by repaying amounts in excess of the new re-determined borrowing base.

(b) Term Loan

At December 31, 2019, the Company had a $35 million (December 31, 2018 – $35 million) Term Loan outstanding (excluding $0.3 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 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, 2019 audited annual consolidated financial statements. The Company was in compliance with all financial covenants at December 31, 2019.

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 (including current portion thereof) and risk management liabilities.

At December 31, 2019, the Company had a working capital deficiency (excluding non-cash risk management assets and liabilities) of $123.9 million which has increased by $115.9 million from $8.0 million on December 31, 2018. The change is attributed to the Company's borrowings under its RCF and Term Loan which were reclassified from non-current to current liabilities as they are each due within one year as at December 31, 2019. The RCF's maturity date is May 31, 2020 due to the inter-creditor relationship between the RCF and the Company's Term Loan which is due October 8, 2020. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension. The reclassification of the RCF and Term Loan have no impact on the Company's debt covenants and the Company continues to be compliant with each of its covenants. Management is actively engaged with the RCF syndicate of lenders and the Term Loan lender and we believe that the RCF and Term Loan will each be extended prior to May 31, 2020. Upon the extension of the RCF and Term Loan, the working capital deficiency will be eliminated. The Company continues its efforts to divest certain non-core assets to improve the balance sheet.

The currently challenged economic environment could result in adverse changes in cash flows, net debt balances, reduction in the borrowing base of the Company's RCF, breach of its financial covenants and there is no guarantee that the RCF and Term Loan will each be extended prior to their respective maturities of May 31, 2020 and October 8, 2020. Accordingly, there is a material uncertainty that may cast significant doubt on the Company’s ability to continue as a going concern. However, the Company remains in compliance with all financial covenants pertaining to its debt, and based on current available information relating to future production volumes, forward commodity pricing, future costs including capital, operating and general and administrative, forward exchange rates, interest rates and taxes, all of which are subject to measurement uncertainty, management expects to comply with all financial covenants during the subsequent 12 month period.

The following are the contractual maturities of financial liabilities as at December 31, 2019:

$000s	**Total**	**< 1 year**	**1-5 years**
Accounts payable and accrued liabilities	11,362	11,362	—
Risk management liability	1,753	1,679	74
Bank indebtedness and long term debt[(1)]	127,250	127,250	—
Lease obligations	1,398	219	1,179
Total	**141,763**	**140,510**	**1,253**

[(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**
Firm service transportation	**16,871**	**2,016**	**11,691**	**3,164**

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 11 and 16 of the Company’s December 31, 2019 consolidated financial statements.

CAPITAL EXPENDITURES

Capital expenditures (excluding acquisitions and dispositions) totaled $4.4 million in the fourth quarter of 2019, compared to $12.7 million in 2018. The Company participated in the drilling activities for 3 (0.05 net) Cardium light oil wells in Ferrier during the fourth quarter and recognized capital expenditures related to the 4 (1.55 net) Cardium light oil wells drilled during the third quarter.

Capital expenditures (excluding acquisitions and dispositions) totaled $18.1 million in the year ended December 31, 2019, compared to $24.1 million in 2018. The decrease from the prior year is attributed to the Company's strategy to prioritize debt repayment and moderate capital spending.

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, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Drill and complete	**3,604**	10,503	**12,871**	16,510
Oil and gas equipment	**283**	1,636	**3,635**	4,177
Land and lease	**17**	23	**37**	1,635
Office	**8**	60	**24**	58
Capitalized general and administrative expense	**439**	438	**1,506**	1,718
Total capital expenditures	**4,351**	**12,660**	**18,073**	**24,098**
Gross (net) wells spud	**3 (0.5)**	**6 (2.7)**	**10 (3.1)**	**10 (4.3)**

During the year ended December 31, 2019, Petrus divested of non-core assets for approximately $0.7 million. Petrus divested non-core assets for approximately $0.4 million during the year ended December 31, 2018.

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

Dispositions ($000s)	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Dispositions	—	6	**651**	448
Total dispositions	**—**	**6**	**651**	**448**

SUMMARY OF QUARTERLY RESULTS

($000s unless otherwise noted)	Dec. 31, 2019	Sept. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018	Sept. 30, 2018	Jun. 30, 2018	Mar. 31, 2018
Average Production								
Natural gas (mcf/d)	32,641	30,998	32,350	32,145	30,480	33,461	39,126	45,543
Oil (bbl/d)	1,834	1,247	1,679	1,704	1,358	1,243	1,484	1,530
NGLs (bbl/d)	1,018	1,372	1,576	1,444	1,496	1,519	1,241	1,475
Total (boe/d)	**8,292**	**7,785**	**8,647**	**8,505**	**7,934**	**8,338**	**9,246**	**10,596**
Total (boe)	**762,874**	**716,220**	**786,819**	**765,488**	**730,819**	**767,095**	**841,316**	**953,598**
Financial Results								
Oil and natural gas revenue	20,998	12,517	17,652	20,231	16,064	20,030	19,321	25,301
Royalty expense	(2,218)	(1,182)	(1,355)	(2,359)	(2,436)	(2,391)	(2,137)	(4,674)
Net oil and natural gas revenue	**18,780**	**11,335**	**16,297**	**17,872**	**13,628**	**17,639**	**17,184**	**20,627**
Transportation expense	(991)	(893)	(959)	(971)	(855)	(749)	(988)	(1,197)
Operating expense	(3,407)	(3,181)	(3,405)	(2,880)	(3,851)	(3,800)	(3,841)	(4,160)
Operating netback	**14,382**	**7,261**	**11,933**	**14,021**	**8,922**	**13,090**	**12,355**	**15,270**
Realized gain (loss) on derivatives	(1,417)	360	(800)	513	(573)	(2,061)	(625)	298
Other income	7	21	78	—	268	69	103	—
General and administrative expense	(1,459)	(776)	(530)	(879)	(1,065)	(1,317)	(1,372)	(1,430)
Cash finance expense	(1,939)	(2,230)	(2,126)	(1,945)	(2,370)	(1,941)	(2,097)	(1,865)
Decommissioning expenditures	(314)	(209)	(189)	(137)	(152)	(155)	—	(168)
Corporate netback and funds flow	**9,260**	**4,427**	**8,366**	**11,573**	**5,030**	**7,685**	**8,364**	**12,105**
Oil and natural gas revenue	**20,998**	**12,517**	**17,652**	**20,231**	**16,064**	**20,030**	**19,321**	**25,301**
Per share - basic	0.42	0.25	0.36	0.41	0.32	0.40	0.39	0.51
Per share - fully diluted	0.42	0.25	0.36	0.41	0.32	0.40	0.39	0.51
Net income (loss)	**(3,176)**	**(29,569)**	**2,863**	**(12,138)**	**21,063**	**(8,048)**	**(10,615)**	**(5,684)**
Per share - basic	(0.06)	(0.60)	0.06	(0.25)	0.43	(0.16)	(0.21)	(0.11)
Per share - fully diluted	(0.06)	(0.60)	0.06	(0.25)	0.43	(0.16)	(0.21)	(0.11)
Common shares outstanding (000s)								
Basic	49,469	49,469	49,469	49,469	49,492	49,492	49,492	49,492
Fully diluted	49,469	49,469	49,469	49,469	49,492	49,492	49,492	49,492
Weighted average shares outstanding (000s)								
Basic	49,469	49,469	49,469	49,483	49,492	49,492	49,492	49,492
Fully diluted	49,469	49,469	49,469	49,483	49,492	49,492	49,492	49,492
Total assets	289,225	296,367	328,912	336,974	341,820	322,335	330,359	343,161
Net debt	(123,744)	(128,553)	(130,619)	(136,382)	(139,214)	(131,603)	(135,111)	(142,238)

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 10,596 boe/d in the first quarter of 2018 to 8,292 boe/d in the fourth quarter of 2019. The 22% production decrease is attributable to Petrus' shift in focus to liquids production growth in order to maximize value in light of the current natural gas commodity price environment as well as certain development activity postponed to prioritize debt repayment. In addition the decrease is due to certain production volume in the Foothills area being shut-in due to uneconomic natural gas pricing.

Commodity price improvements enable higher reinvestment in exploration, development and acquisition activities 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, 2019	December 31, 2018	December 31, 2017
Oil and natural gas revenue	**71,398**	**80,716**	**90,569**
Per share - basic	1.44	1.63	1.85
Per share - fully diluted	1.44	1.63	1.85
Net loss	**(42,176)**	**(3,284)**	**(111,261)**
Per share - basic	(0.85)	(0.07)	(2.28)
Per share - fully diluted	(0.85)	(0.07)	(2.28)
Common shares outstanding (000s)			
Basic	49,469	49,492	49,492
Fully diluted	49,469	49,492	49,492
Weighted avg. shares outstanding (000s)			
Basic	49,469	49,492	48,825
Fully diluted	49,469	49,492	48,825
Total assets	**289,225**	**341,820**	**353,445**
Non-current liabilities	**42,346**	**171,646**	**173,272**

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, 2019.

OTHER FINANCIAL INFORMATION

Significant accounting policies

The Company's significant accounting policies can be read in note 3 of the Company's consolidated financial statements as at and for the year ended December 31, 2019.

New standards and interpretations

The Company's discussion on new standards and interpretations can be read in note 3 of the Company's consolidated financial statements as at and for the period ended December 31, 2019.

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, 2019 and have concluded that the Company's DC&P are effective at December 31, 2019 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, 2019, 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, 2019. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as at December 31, 2019, 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" and "net debt". 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, in the following table, 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, 2019		Three months ended Dec. 31, 2018		Twelve months ended December 31, 2019		Twelve months ended December 31, 2018	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	20,998	27.52	16,064	22.01	71,398	23.55	80,716	24.52
Royalty expense	(2,218)	(2.91)	(2,436)	(3.34)	(7,114)	(2.35)	(11,638)	(3.54)
Net oil and natural gas revenue	**18,780**	**24.61**	**13,628**	**18.67**	**64,284**	**21.20**	**69,078**	**20.98**
Transportation expense	(991)	(1.30)	(855)	(1.17)	(3,814)	(1.26)	(3,789)	(1.15)
Operating expense	(3,407)	(4.47)	(3,851)	(5.28)	(12,873)	(4.25)	(15,652)	(4.75)
Operating netback	**14,382**	**18.84**	**8,922**	**12.22**	**47,597**	**15.69**	**49,637**	**15.08**
Realized loss on financial derivatives	(1,417)	(1.86)	(573)	(0.79)	(1,344)	(0.44)	(2,961)	(0.90)
Other income	7	—	267	0.37	106	0.03	440	0.13
General & administrative expense	(1,459)	(1.91)	(1,065)	(1.46)	(3,644)	(1.20)	(5,184)	(1.57)
Interest expense	(1,939)	(2.54)	(2,370)	(3.25)	(8,241)	(2.72)	(8,273)	(2.51)
Decommissioning expenditures	(314)	(0.41)	(151)	(0.21)	(849)	(0.28)	(475)	(0.14)
Funds flow and corporate netback	**9,260**	**12.12**	**5,030**	**6.88**	**33,625**	**11.08**	**33,184**	**10.09**

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, right-of-use lease obligations, 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, 2019**	**As at December 31, 2018**
Adjusted current assets[(1)]	**14,620**	14,035
Less: adjusted current liabilities[(1)]	**(138,364)**	(21,827)
Less: long term debt	**—**	(131,422)
Net debt	**(123,744)**	**(139,214)**

[(1)]Adjusted for unrealized risk management assets, liabilities, lease obligations and unrealized deferred share unit liabilities.

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2019, 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.

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 reserves 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. In 2019, the P+P FD&A and F&D costs including changes in FDC can generate non meaningful information because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs.

Reserve Life Index

Reserve life index is defined as total reserves by category divided by teh 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.

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 or other purposes.

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 consolidated financial statements as at and for the twelve months ended December 31, 2019. 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: the anticipated impacts of TSP; continued expansion of the NGTL system and low Alberta natural gas storage levels; Petrus' ability to modify its operations; Petrus' business plan and expected debt repayment in 2020 and the anticipated results thereof; the Closing of the Disposition, including the timing and results therof; Petrus' expected drilling and operations activities in 2020; the results of Petrus' 2019 capital plan and the targets thereof; Petrus' 2020 capital plan and the expected results thereof; expectations regarding the adequacy of Petrus' liquidity and the funding of its financial liabilities; Petrus' ability to extend the RCF and Term Loan and the timing thereof; the impact of the current economic environment on Petrus; the performance characteristics of the Company's crude oil, NGL and natural gas properties; future prospects; the focus of and timing of capital expenditures; access to debt and equity markets; 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.

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.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Petrus' prospective results of operations including, without limitation, its ability to repay debt, which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. Petrus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits Petrus will derive therefrom. Petrus has included the FOFI in order to provide readers with a more complete perspective on Petrus' future operations and such information may not be appropriate for other purposes.

These forward-looking statements and FOFI are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward-looking statements and FOFI, 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*

Petrus Resources

CONSOLIDATED ANNUAL FINANCIAL STATEMENTS

As at and for the years ended December 31, 2019 and 2018

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, 2019 and 2018, 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, 2019 and 2018, 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.

Material uncertainty related to going concern

We draw attention to note 2(a) in the consolidated financial statements, which indicates that the Company's continued successful operations are dependent on its ability to restructure its debt or obtain additional financing. As stated in Note 2(a) these events or conditions indicate that a material uncertainty exists that casts significant doubt on the Company's ability to continue as a going concern. Our opinion is not modified in respect of this matter.

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
February 18, 2020

CONSOLIDATED BALANCE SHEETS

(Presented in 000's of Canadian dollars)

As at	December 31, 2019	December 31, 2018
ASSETS		
Current		
Cash	256	63
Deposits and prepaid expenses	1,328	1,297
Accounts receivable *(note 16)*	13,036	12,675
Risk management asset *(note 11)*	—	6,786
Total current assets	**14,620**	**20,821**
Non-current		
Risk management asset *(note 11)*	11	2,749
Exploration and evaluation assets *(notes 5 and 6)*	36,116	42,410
Property, plant and equipment *(notes 5 and 7)*	238,478	275,840
Total assets	**289,225**	**341,820**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	—	380
Current portion of long term debt *(note 8)*	127,002	—
Accounts payable and accrued liabilities *(note 16)*	11,362	21,646
Risk management liability *(note 11)*	1,679	—
Lease obligations *(note 9)*	136	—
Total current liabilities	**140,179**	**22,026**
Non-current liabilities		
Long term debt *(note 8)*	—	131,422
Lease obligations *(note 9)*	1,013	—
Decommissioning obligation *(note 10)*	41,259	40,224
Risk management liability *(note 11)*	74	—
Total liabilities	**182,525**	**193,672**
Shareholders' equity		
Share capital *(note 12)*	430,119	430,119
Contributed surplus	9,112	8,384
Deficit	(332,531)	(290,355)
Total shareholders' equity	**106,700**	**148,148**
Total liabilities and shareholders' equity	**289,225**	**341,820**

Going concern (note 2)
Commitments (note 20)
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, 2019	Year ended December 31, 2018
REVENUE		
Oil and natural gas revenue *(note 21)*	**71,398**	**80,716**
Royalty expense	(7,114)	(11,638)
Net oil and natural gas revenue	**64,284**	**69,078**
Other income	106	440
Net gain (loss) on financial derivatives *(note 11)*	(12,617)	4,549
	51,773	**74,067**
EXPENSES		
Operating *(note 14)*	12,873	15,652
Transportation	3,814	3,789
General and administrative *(note 15)*	3,644	5,184
Share-based compensation *(note 12)*	401	576
Finance *(note 18)*	9,513	9,797
Exploration and evaluation *(note 6)*	2,004	1,938
Depletion and depreciation *(note 7)*	36,564	40,423
Loss (gain) on sale of assets *(note 5)*	481	(8)
Impairment *(notes 6 and 7)*	24,655	—
Total expenses	**93,949**	**77,351**
NET LOSS AND COMPREHENSIVE LOSS	**(42,176)**	**(3,284)**
Net loss per common share		
Basic and diluted *(note 13)*	**(0.85)**	**(0.07)**

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, 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**
Net loss	—	—	(42,176)	(42,176)
Share-based compensation *(note 12)*	—	728	—	728
Balance, December 31, 2019	**430,119**	**9,112**	**(332,531)**	**106,700**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Presented in 000's of Canadian dollars)

	Year ended December 31, 2019	Year ended December 31, 2018
OPERATING ACTIVITIES		
Net loss	**(42,176)**	**(3,284)**
Adjust items not affecting cash:		
Share-based compensation *(note 12)*	401	576
Unrealized loss (gain) on financial derivatives (*note 11)*	11,273	(7,510)
Non-cash finance expenses *(note 18)*	1,272	1,524
Depletion and depreciation *(note 7)*	36,564	40,423
Impairment *(notes 6 and 7)*	24,655	—
Exploration and evaluation expense *(note 6)*	2,004	1,938
Loss (gain) on sale of assets *(note 5)*	481	(8)
Decommissioning expenditures *(note 10)*	(849)	(475)
Funds flow	**33,625**	**33,184**
Change in operating non-cash working capital *(note 19)*	(5,803)	(4,764)
Cash flows from operating activities	**27,822**	**28,420**
FINANCING ACTIVITIES		
Repayment of revolving credit facility	(4,749)	(600)
Repayment of bank indebtedness	(381)	(3,464)
Transaction costs on debt	—	(350)
Repayment of lease liabilities *(note 9)*	(400)	—
Change in financing non-cash working capital *(note 19)*	196	298
Cash flows used in financing activities	**(5,334)**	**(4,116)**
INVESTING ACTIVITIES		
Property and equipment acquisitions *(note 5)*	—	(285)
Property and equipment dispositions *(note 5)*	—	50
Exploration and evaluation asset dispositions (acquisition) *(note 5)*	651	(92)
Exploration and evaluation asset expenditures *(note 6)*	(394)	(1,486)
Petroleum and natural gas property expenditures *(note 7)*	(17,655)	(21,777)
Other capital expenditures	(24)	(60)
Change in investing non-cash working capital *(note 19)*	(4,873)	(615)
Cash used in investing activities	**(22,295)**	**(24,265)**
Increase in cash	193	39
Cash, beginning of period	63	24
Cash, end of period	**256**	**63**
Cash interest paid *(note 18)*	8,241	8,272

See accompanying notes to the interim consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2019 and 2018

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, 2019 and 2018, were approved by the Company's Audit Committee and Board of Directors on February 18, 2020.

2. BASIS OF PRESENTATION

(a) Going Concern

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business.

The Company's Term Loan is due October 8, 2020. The revolving credit facility ("RCF")'s maturity date is May 31, 2020 due to the inter-creditor relationship between the two debt instruments. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension of the RCF. The borrowings under the RCF and the Term Loan are classified as current liabilities in the December 31, 2019 consolidated financial statements which has no impact on the debt covenants and the Company remains in compliance with each of its covenants. However, the reclassification of the debt instruments resulted in a working capital deficiency (excluding non-cash risk management assets and liabilities) of $123.9 million as of December 31, 2019. For the year ended December 31, 2019 the Company generated funds flow of $33.6 million and reduced its debt. Management is actively engaged with the RCF syndicate of lenders and the Term Loan lender. However, there can be no certainty as to the ability of the Company to successfully restructure its RCF and Term Loan or obtain new financing.

Accordingly, there is a material uncertainty that may cast significant doubt on the Company's ability to continue as a going concern. These financial statements do not include adjustments to the recoverability and classification of recorded asset and liabilities and related expenses that might be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and liquidate its liabilities and commitments in other than the normal course of business at amounts different from those in the accompanying consolidated financial statements. Such adjustments could be material.

(b) 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").

(c) 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.

(d) 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 has power 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.

(e) 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 of variables 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.

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 forecast 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.

(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 Company, the fair value of the DSUs is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus.

(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.

(o) New standards and interpretations

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 are 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 re-measurement 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 had adopted IFRS 16 using the modified retrospective approach.

On initial adoption, the Company elected 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;

The Company has identified ROU assets which are included in property plant and equipment and lease liabilities primarily related to office space. The recognition of the present value of minimum lease payments resulted in an additional $0.7 million of right-of-use assets and associated lease liabilities as initial transition adjustment on January 1, 2019. The Company has recognized lease liabilities in relation to lease arrangements previously disclosed as operating lease commitments under IAS 17 that meet the criteria of a lease under IFRS 16. Upon recognition, the Company's weighted average incremental borrowing rate used in measuring lease liabilities was 7.5 percent. Refer to note 9 for additional information.

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

Acquisition and disposal
During the year ended December 31, 2019, the Company disposed of certain exploration and evaluation assets for $0.7 million and recorded a net loss of $0.5 million from this disposition.

During the year ended December 31, 2018, the Company 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.

Asset exchange agreement
On March 13, 2018, the Company 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**

6. EXPLORATION AND EVALUATION ASSETS

The components of the Company's exploration and evaluation ("E&E") assets are as follows:

$000s	
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	70
Property disposition *(note 5)*	(58)
Transfers to property, plant and equipment *(note 7)*	(749)
Balance, December 31, 2018	**42,410**
Additions	18
Disposition *(note 5)*	(1,177)
Exploration and evaluation expense	(2,004)
Capitalized G&A	376
Capitalized share-based compensation *(note 12)*	32
Impairment	(3,086)
Transfers to property, plant and equipment *(note 7)*	(453)
Balance, December 31, 2019	**36,116**

For the year ended December 31, 2019, the Company incurred exploration and evaluation expense of $2.0 million, which relates to expired and nearly expired undeveloped, non-core land (2018 – $1.9 million).

During the year ended December 31, 2019, the Company capitalized $0.4 million of general and administrative expenses ("G&A") (2018 – $0.4 million) and $0.03 million of non-cash share-based compensation directly attributable to exploration activities (2018 – $0.07 million).

As at December 31, 2019, the book value of the Company's net assets was greater than its market capitalization. The Company considered this to be an indicator of impairment and performed an impairment test on all CGUs. The Company determined the fair value less costs of disposal for its two non-core CGUs based on interest expressed during the sales process for its Foothills and Central Alberta assets. The Company recorded an impairment loss of $3.1 million on its E&E assets in the Foothills and Central Alberta CGU during the year ended December 31, 2019. For the Ferrier CGU, no impairment charge was required.

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, 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	212	—	212
Transfers from exploration and evaluation assets *(note 6)*	749	—	749
Depletion & depreciation	—	(40,423)	(40,423)
Decrease in decommissioning provision *(note 10)*	(438)	—	(438)
Balance, December 31, 2018	**801,090**	**(525,250)**	**275,840**
Additions	16,550	—	16,550
Transition adjustment of right of use asset[1]	742	—	742
Addition of right of use asset[1]	709		709
Capitalized G&A	1,129	—	1,129
Capitalized share-based compensation *(note 12)*	97	—	97
Transfers from exploration and evaluation assets *(note 6)*	453	—	453
Depletion & depreciation	—	(36,564)	(36,564)
Increase in decommissioning provision *(note 10)*	1,091	—	1,091
Impairment	—	(21,569)	(21,569)
Balance, December 31, 2019	**821,861**	**(583,383)**	**238,478**

[1] *Right of use asset pertains to corporate office lease.*

At December 31, 2019, estimated future development costs of $267.7 million (2018 – $291.2 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, 2019, the Company capitalized $1.1 million of general and administrative expenses ("G&A") (2018 – $1.3 million) and non-cash share-based compensation of $0.1 million (2018 – $0.2 million), directly attributable to development activities.

As at December 31, 2019, the book value of the Company's net assets was greater than its market capitalization. The Company considered this to be an indicator of impairment and performed an impairment test of each of its CGUs. The Company determined the fair value less costs of disposal for its two non-core CGUs based on interest expressed during the sales process for its Foothills and Central Alberta assets. The Company recorded an impairment loss of $21.6 million on its PP&E assets in the Foothills and Central Alberta CGUs during the year ended December 31, 2019. For the Ferrier CGU the recoverable amount exceeded the carrying value therefore no impairment was recorded. The recoverable amount, a level 3 input on the fair value hierarchy (see note 4), was estimated at fair value less costs of disposal based on proved plus probable reserves and applying an after-tax discount rate ranging from 9% to 10% on the estimated future cash flow. The Company uses the following forward commodity price estimates:

Year	Canadian Light Sweet	AECO $/MMbtu
2020	73.84	2.04
2021	78.51	2.27
2022	78.73	2.81
2023	80.30	2.89
2024	81.91	2.98
2025	83.54	3.06
2026	85.21	3.15
2027	86.92	3.24
2028	88.66	3.33
2029	90.43	3.42
2030	92.24	3.51

Escalation rate of 2.0% thereafter.

At December 31, 2019, the carrying balance of the right of use asset was $1.2 million.

8. DEBT

Petrus has 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, 2019, the RCF was comprised of a $20 million operating facility and a $78 million syndicated term-out facility. Lender consent is required for borrowings exceeding $93 million. The syndicated term-out facility and the amount of borrowing that requires lender consent will be reduced by $2 million on March 31, 2020. The Company has provided collateral by way of a debenture over all of the present and after acquired property of the Company. The RCF's maturity date is May 31, 2020 which was set prior to the Term Loan maturity of October 8, 2020 due to the inter-creditor relationship between the RCF and the Term Loan. The Company requires an extension or refinancing of its Term Loan before the syndicate of lenders will contemplate an extension to the RCF.

At December 31, 2019, the Company had a $0.7 million letter of credit outstanding against the RCF (December 31, 2018 – $0.7 million) and had drawn $92.3 million against the RCF (December 31, 2018 – $97.0 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, 2020. In the event that the lenders reduce the borrowing base below the amount drawn at the time of redetermination, the Company has 60 days to eliminate any shortfall by repaying amounts in excess of the new re-determined borrowing base.

(b) Term Loan

At December 31, 2019 the Company had a $35 million (December 31, 2018 – $35 million) Term Loan outstanding (excluding $0.3 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 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.

Liquidity

At December 31, 2019, the Company had a working capital deficiency (excluding non-cash risk management assets and liabilities) of $123.9 million which has increased due to the reclassification of the Company's borrowings under its RCF and Term Loan. See note 2(a).

However, the Company remains in compliance with all financial covenants pertaining to its debt, and based on current available information relating to future production volumes, forward commodity pricing, future costs including capital, operating and general and administrative, forward exchange rates, interest rates and taxes, all of which are subject to measurement uncertainty, management expects to comply with all financial covenants during the subsequent 12 month period.

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 Total Debt at the date of the annual borrowing base redetermination which will take place on or before May 31, 2020.

The key financial covenants as at December 31, 2019 are summarized in the following table. At December 31, 2019 the Company is in compliance with all financial covenants.

Financial Covenant Description	**Required Ratio**	**As at December 31, 2019**
Working Capital Ratio	Over 1.00	1.73
Proved Asset Coverage Ratio [1]	Over 1.25	1.90
PDP Asset Coverage Ratio [1]	Over 1.00	1.08
Debt to EBITDA Ratio	Under 3.50	2.99

[1] Calculations are based upon the Company's December 31, 2019 reserve report evaluated by Sproule Associates Ltd.

9. LEASES

The Company's lease obligations are as follows:

$000s	
Balance, January 1, 2019	**742**
Additions	709
Finance expense	98
Lease payments	(400)
Balance, December 31, 2019	**1,149**

The Company's future commitments associated with its lease obligations are as follows:

$000s	**As at December 31, 2019**
Less than 1 year	219
1 to 3 years	810
4 to 5 years	369
After 5 years	—
Total lease payments	1,398
Amounts representing finance expense	(249)
Present value of lease obligation	1,149
Current portion of lease obligation	136
Non-current portion of lease obligation	1,013

10. 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 1.76 percent and an inflation rate of 1.75 percent (2018 – 2.13 percent and 2.00 percent, respectively). Changes in estimates in 2018 and 2019 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 $41.3 million as at December 31, 2019 ($40.2 million at December 31, 2018). The undiscounted, uninflated total future liability at December 31, 2019 is $41.4 million ($41.6 million at December 31, 2018). 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, 2017	**40,654**
Property acquisitions	224
Property dispositions	(629)
Liabilities incurred	393
Liabilities settled	(475)
Change in estimates	(830)
Accretion expense	887
Balance, December 31, 2018	**40,224**
Property dispositions	(24)
Liabilities incurred	729
Liabilities settled	(849)
Change in estimates	402
Accretion expense	777
Balance, December 31, 2019	**41,259**

11. 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, 2019:

Contract Period	Type	Total Daily Volume (GJ)	Average Price (CDN$/GJ)
Natural Gas Swaps			
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	9,000	$1.91
Jan. 1, 2020 to Mar. 31, 2021	Fixed price	2,000	$1.50
Nov. 1, 2019 to Oct. 31, 2020	Fixed price	3,500	$1.58
Jan. 1, 2020 to Oct. 31, 2021	Fixed price	1,000	$1.53
Apr. 1, 2020 to Oct. 31, 2020	Fixed price	4,000	$1.52
Apr. 1, 2020 to Mar. 31, 2021	Fixed price	2,000	$1.45
Nov. 1, 2020 to Mar. 31, 2021	Fixed price	2,000	$1.98
Apr. 1, 2021 to Oct. 31, 2021	Fixed price	3,000	$1.63

Contract Period	Type	Total Daily Volume (Bbl)	Average Price (CDN$/Bbl)
Crude Oil Swaps			
Jan. 1, 2020 to Mar. 31, 2020	Fixed price	800	$70.20
Jan. 1, 2020 to Jun. 30, 2020	Fixed price	300	$77.25
Jan. 1, 2020 to Dec. 31, 2020	Fixed price	350	$76.70
Apr. 1, 2020 to Jun. 30, 2020	Fixed price	500	$75.52
Jul. 1, 2020 to Sep. 30, 2020	Fixed price	300	$77.86
Jul. 1, 2020 to Dec. 31, 2020	Fixed price	300	$75.57
Oct. 1, 2020 to Dec. 31, 2020	Fixed price	100	$68.26
Jan. 1, 2021 to Mar. 31, 2021	Fixed price	200	$71.06
Jan. 1, 2021 to Jun. 30, 2021	Fixed price	300	$74.02
Jul. 1, 2021 to Dec. 31, 2021	Fixed price	300	$72.80

Contract Period	Type	Average Rate (%)	Notional Amount (000s CDN$)
Interest Rate Swaps			
Jan. 1, 2020 to Dec. 31, 2022	Fixed rate	2.34	$20,000

Risk management asset and liability:

$000s At December 31, 2019	Asset	Liability
Current commodity derivatives	—	1,679
Non-current commodity derivatives	11	74
	11	**1,753**
$000s At December 31, 2018		
Current commodity derivatives	6,786	—
Non-current commodity derivatives	2,749	—
	9,535	**—**

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

$000s	Year ended December 31, 2019	Year ended December 31, 2018
Realized loss on financial derivatives	(1,344)	(2,961)
Unrealized gain (loss) on financial derivatives	(11,273)	7,510
Net gain (loss) on financial derivatives	**(12,617)**	**4,549**

12. 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*)*	Number of Shares	Amount
Balance, December 31, 2017 and December 31, 2018	**49,491,840**	**430,119**
Cancelled[(1)]	(22,482)	—
Balance, December 31, 2019	**49,469,358**	**430,119**

[(1)]On February 4, 2019, 22,482 shares were cancelled pursuant to the Arrangement Agreement between Phoscan Chemical Corp. and Petrus Resources Ltd (and the 3 year sunset clause therein).

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, 2019, 2,361,958 (December 31, 2018 – 3,082,880) stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted average exercise price
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**
Granted	1,386,357	$0.33
Cancelled/forfeited	(707,069)	$1.74
Expired	(1,400,210)	$4.20
Balance, December 31, 2019	**2,361,958**	**$1.19**
Exercisable, December 31, 2019	**35,000**	**$15.13**

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)
$0.26 - $0.86	1,493,468	$0.43	2.62	—	—	—
$1.49 - $2.33	833,490	$2.02	2.02	—	—	—
$14.00	35,000	$14.00	0.11	35,000	$14.00	0.11
	2,361,958	**$1.75**	**1.69**	**35,000**	**$14.00**	**0.11**

During the year ended December 31, 2019 and the year ended December 31, 2018, the Company granted options which vest equally over three years, and upon vesting, expire 30 business days thereafter. The weighted average fair value of each option granted during the year ended December 31, 2019 of $0.11 (2018 – $0.30) was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2019	2018
Risk free interest rate	1.57% - 1.83%	1.70% - 1.90%
Expected life (years)	1.08 - 3.08	1.08 - 3.08
Estimated volatility of underlying common shares (%)	73% - 81%	63% - 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, 2019, 739,046 DSUs were issued and outstanding. The Company recorded the DSUs in its share-based compensation for the year ended December 31, 2019.

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

$000s	Year ended December 31, 2019	Year ended December 31, 2018
Expensed	401	576
Capitalized to exploration and evaluation assets	32	70
Capitalized to property, plant and equipment	97	212
Deferred share units	198	—
Total share-based compensation	**728**	**858**

13. LOSS PER SHARE

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

	Year ended December 31, 2019	Year ended December 31, 2018
Net loss for the period ($000s)	**(42,176)**	**(3,284)**
Weighted average number of common shares – basic (000s)	49,472	49,492
Weighted average number of common shares – diluted (000s)	49,472	49,492
Net loss per common share – basic	**($0.85)**	**($0.07)**
Net loss per common share – diluted	**($0.85)**	**($0.07)**

In computing diluted loss per share for the year ended December 31, 2019, 2,361,958 outstanding stock options and 739,046 DSUs were considered (December 31, 2018 – 3,082,880 and 296,104, respectively), which were excluded from the calculation as their impact was anti-dilutive.

14. OPERATING EXPENSES

The Company's operating expenses consisted of the following expenditures:

$000s	**2019**	**2018**
Fixed and variable operating expenses	10,668	13,084
Processing, gathering and compression charges	3,167	3,602
Total gross operating expenses	**13,835**	**16,686**
Overhead recoveries	(962)	(1,034)
Total net operating expenses	**12,873**	**15,652**

15. GENERAL AND ADMINISTRATIVE EXPENSES

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

$000s	**2019**	**2018**
Gross general and administrative expense	6,217	8,229
Capitalized general and administrative expense	(1,506)	(1,718)
Overhead recoveries	(1,067)	(1,327)
General and administrative expense	**3,644**	**5,184**

16. 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 $13.0 million of accounts receivable outstanding at December 31, 2019 (December 31, 2018 – $12.7 million), $5.7 million is owed from 3 parties (December 31, 2018 – $7.1 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, 2019, the Company had an allowance for doubtful accounts of $0.4 million (December 31, 2018 – $0.2 million). At December 31, 2019, 95% of Petrus' accounts receivable were aged less than 120 days and 5% of Petrus' accounts receivable were aged greater than 120 days. The Company does not anticipate any material 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, 2019, the Company had a $98 million RCF with a borrowing limit of $93 million, on which $92.3 million was drawn (December 31, 2018 – $97.0 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, 2020. See additional discussion in note 8.

The following are the contractual maturities of financial liabilities as at December 31, 2019:

$000s	Total	< 1 year	1-5 years
Accounts payable and accrued liabilities	11,362	11,362	0
Risk management liability	1,753	1,679	74
Bank indebtedness and long term debt[(1)]	127,250	127,250	0
Lease obligations	1,398	219	1,179
Total	**141,763**	**140,510**	**1,253**

[(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. To manage exposure to interest rate volatility, the Company entered into interest rate swap contracts (note 11). A 1% increase in the Canadian prime interest rate during the year ended December 31, 2019 would have increased net loss by approximately $1.1 million, respectively, which relates to interest expense on the average outstanding RCF and Term Loan, net of any interest rate swaps to fix the interest rate on loans, during the year assuming that all other variables remain constant (December 31, 2018 – increase net loss by $1.3 million). A 1% decrease in the Canadian prime interest rate during the year 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 11). 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, 2019, it was estimated that a $0.25/GJ decrease in the price of natural gas would have decreased net loss by $1.5 million (December 31, 2018 – $1.8 million). An opposite change in commodity prices would result in an opposite impact on net loss. As at December 31, 2019, it was estimated that a $5.00/CDN WTI/bbl decrease in the price of oil would have decreased net loss by $2.0 million (December 31, 2018 – $4.0 million). An opposite change in commodity prices would result in an opposite impact on net loss.

17. 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.

18. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	2019	2018
Cash:		
Interest	8,241	8,273
Total cash finance expenses	8,241	8,273
Non-cash:		
Deferred financing costs	495	637
Accretion on decommissioning obligations *(note 10)*	777	887
Total non-cash finance expenses	1,272	1,524
Total finance expenses	**9,513**	**9,797**

19. SUPPLEMENTAL CASH FLOW INFORMATION

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

$000s	2019	2018
Source (use) in non-cash working capital:		
Deposits and prepaid expenses	(31)	133
Transaction costs on debt	196	(18)
Accounts receivable	(361)	(1,087)
Accounts payable and accrued liabilities	(10,284)	(4,110)
	(10,480)	**(5,082)**
Operating activities	(5,803)	(4,764)
Financing activities	196	298
Investing activities	(4,873)	(615)

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, 2018	**380**	**97,000**	**34,422**	**131,802**
Cash flows	(380)	(4,750)	—	(5,130)
Non-cash changes	—	—	330	330
Balance, December 31, 2019	**—**	**92,250**	**34,752**	**127,002**

20. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

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

$000s	Total	< 1 year	1-5 years	> 5 years
Firm service transportation	16,871	2,016	11,691	3,164

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.

21. REVENUE

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

$000s	2019	2018
Production Revenue		
Oil and condensate sales	37,815	35,684
Natural gas sales	22,052	23,453
Natural gas liquids sales	10,917	21,186
Total oil and natural gas production revenue	**70,784**	**80,323**
Royalty revenue	614	393
Total oil and natural gas revenue	**71,398**	**80,716**

22. 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	2019	2018
Salaries, consulting fees, benefits and director fees, gross	1,646	1,563
Share based compensation, gross	473	274
	2,119	**1,837**

23. DEFERRED INCOME TAXES

$000s	2019	2018
Loss before taxes	(42,176)	(3,284)
Combined federal and provincial tax rate	26.5%	27.0%
Computed "expected" tax recovery	(11,177)	(887)
Increase/(decrease) in taxes resulting from:		
Permanent items	4	7
Share based payments	108	156
Share issuance costs	(94)	(95)
Impact of rate change	9,767	—
True up and other	(355)	(1,135)
Unrecognized deferred income tax asset	1,747	1,954
Deferred tax expense (recovery)	**—**	**—**
Effective tax rate	**—%**	**—%**

The components of the Company's deferred tax position at December 31, 2019 and 2018 are as follows:

$000s	2019	2018
Exploration and evaluation assets and property, plant and equipment	(7,652)	(12,842)
Share issuance costs	155	278
Non capital loss carry-forwards	7,267	15,138
Unrealized hedging loss	230	(2,574)
Deferred tax liability	**—**	**—**

The Company had non-capital losses of approximately $238.5 million (2018 – $217.8 million) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2027 and onwards.

CORPORATE INFORMATION

OFFICERS

Neil Korchinski, P. Eng.
President and
Chief Executive Officer

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

DIRECTORS

Don T. Gray
Chairman
Scottsdale, Arizona

Neil Korchinski
Calgary, Alberta

Patrick Arnell
Calgary, Alberta

Donald Cormack
Calgary, Alberta

Stephen White
Calgary, Alberta

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR
Ernst & Young LLP
Chartered Professional Accountants
Calgary, Alberta

INDEPENDENT RESERVE EVALUATORS
Sproule and Associates
Calgary, Alberta

BANKERS
TD Securities (Syndicate Lead Agent)
Calgary, Alberta

Macquarie Bank Limited
Houston, Texas

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