Petrus Resources

ANNUAL REPORT

December 31, 2016

HIGHLIGHTS

Petrus Resources Ltd. ("Petrus" or the "Company") (TSX: PRQ) is pleased to report operating and financial results for the three and twelve month periods ended December 31, 2016, and to provide 2016 year end reserves information as evaluated by Sproule Associates Limited ("Sproule"). Petrus continues to be committed to operating cost and debt reduction as well as improved capital efficiencies and is focused on organic growth in its core area (Ferrier, Alberta). The Company is targeting liquids rich natural gas in the Cardium formation as well as investing in infrastructure in Ferrier with the objective to maximize the Company's return on investment. The Company's Management's Discussion and Analysis ("MD&A") and audited consolidated financial statements dated as at and for the year ended December 31, 2016 are available on SEDAR (the System for Electronic Document Analysis and Retrieval) at www.sedar.com.

- At year end the Company's net debt[1] ($124.9 million) was 45% lower than year end 2015 ($226.7 million). Fourth quarter cash finance expense was 53% lower in 2016 relative to the prior year. Subsequent to December 31, 2016, Petrus entered into an agreement with Macquarie Bank Limited to extend and pay down its second lien term loan. The loan balance of $35 million is now due in October 2019. The interest rate basis remains unchanged and is currently 7.9% per annum.

- In the fourth quarter of 2016 Petrus generated cash flows from operating activities of $18.8 million, compared to $8.8 million in the fourth quarter of 2015. For the year ended December 31, 2016, Petrus generated cash flows from operating activities of $41.9 million compared to $15.5 million in the prior year. The changes for the three and twelve month periods are explained by changes in non-cash working capital.

- Petrus generated funds from operations[1] of $10.3 million in the fourth quarter of 2016, a 54% increase relative to $6.7 million generated in the fourth quarter of 2015. The increase is due to higher production, lower operating expenses, and improved commodity prices. The increase was offset by $1.4 million of G&A expenses (net of capitalized portion) related to one-time severance costs and annual incentive compensation recognized in the fourth quarter of 2016. For the year ended December 31, 2016, Petrus generated funds from operations of $28.6 million which is 36% lower than $44.6 million in the prior year. The decrease on a full year basis is due to lower production (attributed to the Peace River asset disposition) and lower commodity prices, in addition to higher fourth quarter G&A expenses.

- Fourth quarter production was 8,595 boe/d in 2016 compared to 8,172 boe/d in 2015; this 5% increase is a result of Ferrier development activity. During the fourth quarter, 4 gross (2.2 net) new wells were brought on production. The remaining 2016 development locations are expected to come on production in the first quarter of 2017. Full year production for 2016 was 8,236 boe/d compared to 8,762 boe/d for the year ended December 31, 2015. The decrease is attributed to the sale of Peace River assets offset by enhanced production in Ferrier. Petrus' February 2017 average monthly production is expected to be 9,148 boe/d.

- In 2015 and 2016, Petrus' transformed its operating cost structure through the divestiture of higher cost assets and the construction of a natural gas processing plant in Ferrier. As a result, operating expenses have decreased 67% from $11.00 per boe in the fourth quarter of 2015 to $3.63 per boe in the fourth quarter of 2016. In Ferrier, operating expenses per boe decreased approximately 83% in the fourth quarter of 2016 compared to the fourth quarter of 2015. The decrease is a result of the low cost structure of the Petrus owned and operated Ferrier gas plant, expiration of a third party processing commitment and higher production volume from developmental drilling.

- Petrus ended 2016 with $420.9 million of proved plus probable reserve value before-tax, discounted at 10%, a 5% increase from the December 31, 2015 report, despite the effect of the Peace River asset disposition in 2016 and a lower commodity price forecast used by Sproule. In 2016, the Company realized Finding and Development costs of $9.89/boe and $2.46/boe for Proved Developed Producing ("PDP") and Total Proved ("TP") reserves respectively.

- Petrus' Board of Directors approved a $50 to $60 million capital budget for 2017 (excluding acquisitions and dispositions). Capital is expected to be directed primarily to the development of the Company's Ferrier assets. The program is expected to include drilling 16 gross (11.7 net) Cardium wells at Ferrier. The program also provides for investment in facilities; the processing and compression capability of the Ferrier gas plant is expected to be doubled to reach a capacity of approximately 60 mmcf/d by the fourth quarter of 2017.

- Petrus utilizes financial derivative contracts to mitigate commodity price risk. The Company's realized gain on financial derivatives in 2016 increased the Company's corporate netback[1] by $4.98 per boe compared to $5.18 per boe realized in the prior year.

[1] Refer to "Non-GAAP Financial Measures."

PRESIDENT’S MESSAGE

It’s working.

Despite commodity prices being more challenging than 2015, Petrus accomplished many corporate, operational and reserve successes this year. As with last year, Ferrier played a centric role in these successes and we believe our future growth in the area is further de-risked with each year of drilling and infrastructure development. It is not an exaggeration to say we are more excited about Petrus' prospects for growth now than we ever have been. We don't require improved commodity pricing to achieve this growth, and are protected with strong hedging contracts if prices should fall; we don't require external financing sources, although we may pursue them; and we don't require any additional land in Ferrier, although we are constantly trying to expand our asset base as we have proved in the past. After two difficult years of building, we are now in a position to execute our growth plan.

We continue to focus on our commitment to reduce debt. Since the beginning of 2016 we have reduced our debt by 45% as a result of an equity financing and strategic asset dispositions. From the fourth quarter of 2015, we have lowered our net debt to funds from operations by 64% from 8.4 times to 3.0 times. While proud of our debt reduction, improving financial flexibility remains paramount in our minds and we continue to consider options to reduce these levels even further.

Providing a strategic advantage to us is our dramatically reduced operating costs. From the fourth quarter of 2015, we have achieved a 67% reduction in our operating costs, which were $3.63/boe in the fourth quarter of 2016. Although we have been working on driving down operating costs in all areas, the work we have accomplished specifically in Ferrier is forefront to this reduction.

Our decreasing operating costs and growing infrastructure system have allowed us to continue to expand our asset base in Ferrier. Since doing the Arriva acquisition in the third quarter of 2014, our net undeveloped Ferrier land base has increased by 5 times and our total Ferrier drilling inventory has increased by 4 times. Considering this growth was in very difficult economic times, and with the operating cost advantage we now have in the area, we are confident we will see continued growth in the future, as evidenced by our most recent acquisition.

In 2016 we drilled, or participated in the drilling of, 11 gross (7.3 net) wells, all in Ferrier. These wells earned Petrus an internally estimated full cycle rate of return of 42% and a payout of 2.4 years at strip price forecast (strip price at February 15, 2017), which is the best composite economics in the Company’s history. Our improved operating costs, increased drilling and capital efficiencies and specific reservoir targeting all helped achieve these results. We also achieved significant improvements in several important reserve metrics: our PDP F&D cost was $9.89/boe, which is a 67% improvement from the previous year; our cost to add production was $11,300/boed which is a 78% reduction from the previous year; and we were able to add year over year NAV growth in every reserves category (PDP, TP and P+P), despite a degradation in price forecast and the Peace River disposition.

We are proud of Petrus' performance in 2016. There are continued improvements to be made in 2017, which will be facilitated by a consistent and systematic drilling program throughout the year. We are confident that our solid foundation will enable us to continue adding value to Petrus well into the future.

Neil Korchinski
President, Chief Executive Officer and Director

OPERATIONS UPDATE

Average fourth quarter production on an area level was as follows:

Average production for the three months ended Dec. 31, 2016	Ferrier	Foothills	Central Alberta	Total
Natural gas (mcf/d)	21,599	7,939	7,789	37,327
Oil (bbl/d)	588	338	526	1,452
NGLs (bbl/d)	672	43	207	922
Total (boe/d)	**4,860**	**1,704**	**2,031**	**8,595**
Natural gas sales weighting	***74%***	***78%***	***64%***	***72%***

Average production was 8,595 boe/d (28% oil and liquids) in the fourth quarter of 2016 compared to 8,172 boe/d (36% oil and liquids) in the fourth quarter of 2015.

RECENT ACTIVITY

During the fourth quarter, Petrus drilled 5 gross (2.6 net) wells in the Ferrier area targeting liquids rich natural gas in the Cardium formation. With the addition of these new wells, Petrus' February 2017 monthly production is expected to be 9,148 boe/d. Based on the Company's year-end production and 2016 capital expenditures Petrus added production at a cost of approximately $11,300 per flowing boe/d. Average drill and case costs were lower than comparable wells drilled in 2015 due to new techniques, reduced service costs and improved cycle time.

Using historic data and estimated field production, the Company estimates its corporate base decline production rate to be approximately 28%. Since the acquisition of Arriva Energy Inc. on September 9, 2014 up to this report date, Petrus has drilled 17 wells in the Ferrier area and participated as a working interest partner in 6 additional wells. For the same period, the Company has increased net production in the Ferrier area from approximately 1,000 boe/d to over 5,400 boe/d.

Capital Budget

Petrus' Board of Directors approved a $50 to $60 million capital budget for 2017 (excluding acquisitions and dispositions). Capital is expected to be directed primarily to the development of the Company's Ferrier assets. The program is expected to include drilling 16 gross (11.7 net) Cardium wells at Ferrier. The program also provides for investment in facilities; the processing and compression capability of the Ferrier gas plant is expected to be doubled to reach a capacity of approximately 60 mmcf/d by the fourth quarter of 2017.

Term Loan Extension

On January 24, 2017 Petrus entered into an agreement with Macquarie Bank Limited to extend the Company's $42 million second lien term loan by two years; now due October 2019. Concurrent with the extension, the Company reduced the amount outstanding by $7 million through working capital and available credit facilities. The interest rate on the remaining $35 million balance will remain unchanged at a per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points.

Acquisition and Private Placement

On February 28, 2017 the Company closed an acquisition of certain oil and natural gas interests in the Ferrier area (the "Acquisition") and a non-brokered private placement of 4,078,708 common shares of the Company ("Common Shares") at a purchase price of $2.53 per Common Share, for aggregate gross proceeds of $10.3 million (the "Private Placement"). A portion of the net proceeds of the Private Placement were used to fund the Acquisition and Petrus expects the remainder will be used to fund the Company's 2017 capital program.

ANNUAL GENERAL MEETING

The Company's Annual General & Special Meeting will be held at the Jamieson Place Conference Centre (3rd floor) 308, 4th Ave SW Calgary, Alberta, on Thursday May 18, 2017 at 9:00 a.m. (Calgary time). At the Annual General & Special Meeting, the Company intends to, among other things, request shareholder approval to complete a share consolidation.

RESERVES

Petrus' 2016 year end reserves were evaluated by independent reserves evaluator Sproule and Associates ("Sproule") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2016. Additional reserve information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR.

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

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

As at December 31, 2016	Total Company Interest (1)(3)						
Reserve Category	**Conventional Natural Gas (mmcf)**	**Light and Medium Crude Oil (mbbl)**	**NGL (mbbl)**	**Total (mboe)**	**NPV 0% ($000s)**	**NPV 5% ($000s)**	**NPV 10% ($000s)**
Proved Producing	58,091	1,889	2,250	13,820	259,804	210,611	180,316
Proved Non-Producing	15,510	81	242	2,908	39,223	29,030	23,210
Proved Undeveloped	58,058	1,948	2,770	14,395	190,636	111,867	64,483
Total Proved	**131,660**	**3,918**	**5,262**	**31,123**	**489,664**	**351,508**	**268,009**
Proved + Probable Producing	75,947	2,558	2,933	18,149	372,404	272,303	220,119
Total Probable	**57,722**	**2,966**	**2,317**	**14,903**	**359,686**	**221,114**	**152,878**
Total Proved Plus Probable	**189,383**	**6,884**	**7,579**	**46,027**	**849,349**	**572,622**	**420,888**

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

Petrus ended 2016 with reserve value before-tax discounted at 10% of $420.9 million proved plus probable ("P+P") and $268.0 million total proved ("TP"), respectively. This represents a 5% and 8% increase, respectively, from the December 31, 2015 report, despite a lower commodity price forecast by the independent reserve evaluators. In 2016 Petrus' total company interest reserves decreased 6% to 46.0 mmboe on a P+P basis and 5% on a TP basis to 31.1 mmboe, due to a significant asset disposition in 2016.

FUTURE DEVELOPMENT COST

Future Development Cost ("FDC") reflects Sproule's best estimate of what it will cost to bring the proved and probable undeveloped reserves on production. FDC associated with our total P+P reserves at December 31, 2016 is $260.1 million (undiscounted) and includes 229 gross (126.4 net) booked P+P locations.

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

Future Development Cost ($000s)	Total Proved	Total Proved + Probable
2017	46,496	51,237
2018	97,460	133,360
2019	57,599	83,180
2020	—	1,368
Thereafter	—	—
Total FDC, Undiscounted	**201,556**	**269,144**
Total FDC, Discounted at 10%	**174,468**	**231,281**

PERFORMANCE RATIOS

The following table highlights annual performance ratios for the Company from 2013 to 2016:

	December 31, 2016	December 31, 2015	December 31, 2014	December 31, 2013
Proved Producing				
FD&A ($/boe) [(1)(2)]	**(0.43)**	23.18	35.35	34.72
Reserve Life Index (yr) [(1)]	**4.4**	5.2	4.6	4.2
Reserve Replacement Ratio [(1)]	**0.4**	0.7	5.9	1.4
Total Proved				
FD&A ($/boe) [(1)(2)]	**(15.77)**	16.77	27.44	31.38
Reserve Life Index (yr) [(1)]	**9.8**	10.9	7.3	6.4
Reserve Replacement Ratio [(1)]	**0.5**	2.9	9.1	1.8
Future Development Cost ($000s)	**201,556**	223,409	122,326	17,877
Total Proved + Probable				
FD&A ($/boe) [(1)(2)]	**350.08**	15.4	21.49	21.57
Reserve Life Index (yr) [(1)]	**14.6**	16.4	11.2	11.0
Reserve Replacement Ratio [(1)]	**(0.1)**	3.7	12.7	3.2
Future Development Cost ($000s)	**269,144**	325,325	199,410	40,864

[(1)] Refer to "Oil and Gas Disclosures."
[(2)] Certain changes in FD&A produce non-meaningful figures as discussed in the "Oil and Gas Disclosures."

In 2016, the Company realized F&D costs of $9.89/boe and $2.46/boe for Proved Developed Producing ("PDP") and TP reserves, respectively. This represents a 67% and 88% reduction, respectively, from the prior year as outlined in the following table.

Finding & Development Costs ($/boe)[(1)]	**2016**	**2015**
Proved Developed Producing	**9.89**	29.80
Total Proved	**2.46**	21.02
Proved plus probable [(1)]	**(8.06)**	19.01

[(1)] Refer to "Oil and Gas Disclosures."

MANAGEMENT'S DISCUSSION & ANALYSIS

December 31, 2016

MANAGEMENT'S DISCUSSION & ANALYSIS

The following is management's discussion and analysis ("MD&A") of the financial and operating results of the Company as at and for the three and twelve month periods ended December 31, 2016. The report is dated March 9, 2017 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2016 and 2015. The Company's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are directed to the advisories at the end of this report regarding forward-looking statements and BOE presentation and to the section "Non-GAAP Financial Measures" herein.

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

SELECTED FINANCIAL INFORMATION

OPERATIONS	Twelve months ended Dec. 31, 2016	Twelve months ended Dec. 31, 2015	Three months ended Dec. 31, 2016	Three months ended Sept. 30, 2016	Three months ended Jun. 30, 2016	Three months ended Mar. 31, 2016
Average Production						
Natural gas (mcf/d)	33,964	32,088	37,327	30,009	33,071	35,456
Oil (bbl/d)	1,820	2,838	1,452	1,419	2,200	2,218
NGLs (bbl/d)	755	576	922	680	723	694
Total (boe/d)	**8,236**	**8,762**	**8,595**	**7,100**	**8,435**	**8,821**
Total (boe)	**3,014,348**	**3,198,158**	**790,806**	**653,215**	**767,585**	**802,744**
Natural gas sales weighting	69%	61%	72%	70%	65%	67%
Realized Prices						
Natural gas ($/mcf)	2.39	2.93	3.29	2.53	1.64	2.01
Oil ($/bbl)	45.13	52.47	59.42	44.50	46.68	34.52
NGLs ($/bbl)	17.23	25.09	24.56	15.56	8.47	18.18
Total realized price ($/boe)	**21.40**	**29.43**	**26.97**	**21.06**	**19.32**	**18.18**
Royalty income	0.11	0.14	0.10	0.07	0.12	0.13
Royalty expense	(2.97)	(3.74)	(3.52)	(2.99)	(2.26)	(3.08)
Net oil and natural gas revenue ($/boe)	**18.54**	**25.83**	**23.55**	**18.14**	**17.18**	**15.23**
Operating expense	(6.48)	(8.90)	(3.63)	(6.04)	(7.65)	(8.52)
Transportation expense	(1.48)	(1.64)	(1.50)	(1.49)	(1.30)	(1.62)
Operating netback [1][2] ($/boe)	**10.58**	**15.29**	**18.42**	**10.61**	**8.23**	**5.09**
Realized gain on derivatives ($/boe)	4.98	5.18	0.99	4.06	6.87	7.84
General & administrative expense	(2.56)	(2.35)	(3.78)	(1.69)	(1.86)	(2.72)
Cash finance expense	(3.53)	(4.16)	(2.58)	(3.85)	(3.18)	(4.53)
Corporate netback [1] ($/boe)	**9.47**	**13.96**	**13.05**	**9.13**	**10.06**	**5.68**

FINANCIAL (000s except per share)	Twelve months ended Dec. 31, 2016	Twelve months ended Dec. 31, 2015	Three months ended Dec. 31, 2016	Three months ended Sept. 30, 2016	Three months ended Jun. 30, 2016	Three months ended Mar. 31, 2016
Oil and natural gas revenue	64,840	94,587	21,409	13,805	14,926	14,698
Net loss	(66,988)	(69,031)	(11,842)	(4,702)	(46,334)	(4,110)
Net loss per share						
Basic	(1.51)	(1.96)	(0.26)	(0.10)	(1.02)	(0.10)
Fully diluted [3]	(1.51)	(1.96)	(0.26)	(0.10)	(1.02)	(0.10)
Funds from operations[1]	28,568	44,639	10,317	5,966	7,725	4,558
Funds from operations per share [1]						
Basic	0.64	1.27	0.23	0.13	0.17	0.11
Fully diluted [3]	0.64	1.27	0.23	0.13	0.17	0.11
Capital expenditures	29,246	54,469	10,026	7,231	2,712	9,277
Net acquisitions (dispositions)	(29,718)	938	—	(29,718)	—	—
Common shares outstanding						
Basic	45,349	35,148	45,349	45,349	45,349	45,349
Fully diluted [3]	45,349	35,148	45,349	45,349	45,349	45,349
Weighted average shares outstanding	**44,429**	**35,148**	**45,349**	**45,349**	**45,349**	**41,762**
As at period end						
Total assets	439,967	555,145	439,967	448,404	493,535	544,548
Total liabilities	188,696	311,241	188,696	127,567	156,845	155,000
Shareholders' equity	251,271	243,904	251,271	263,214	267,573	313,936
Net debt [1]	124,915	226,742	124,915	124,310	152,935	157,675

[1] *Refer to "Non-GAAP Financial Measures in the MD&A."*
[2] *In prior periods Petrus included realized gain on derivatives (hedging gain (loss)) in the calculation of operating netback.*
[3] *In computing diluted per share metrics no instruments (performance warrants or stock options) were added to the calculation as their impact is anti-dilutive.*

RESULTS OF OPERATIONS

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Twelve months ended Dec. 31, 2016	Twelve months ended Dec. 31, 2015	Three months ended Dec. 31, 2016	Three months ended Sept. 30, 2016	Three months ended Jun. 30, 2016	Three months ended Mar. 31, 2016
Average production						
Natural gas (mcf/d)	33,964	32,088	37,327	30,009	33,071	35,456
Oil (bbl/d)	1,820	2,838	1,452	1,419	2,200	2,218
NGLs (bbl/d)	755	576	922	680	723	694
Total (boe/d)	**8,236**	**8,762**	**8,595**	**7,100**	**8,435**	**8,821**
Total (boe)	3,014,348	3,198,158	790,806	653,215	767,585	802,744
Revenue (000s)						
Natural Gas	29,684	34,307	11,304	6,975	4,929	6,476
Oil	30,061	54,565	7,939	5,809	9,345	6,967
NGLs	4,763	5,262	2,084	973	558	1,148
Royalty revenue	332	453	82	47	94	107
Oil and natural gas revenue	64,840	94,587	21,409	13,805	14,926	14,698
Average realized prices						
Natural gas ($/mcf)	2.39	2.93	3.29	2.53	1.64	2.01
Oil ($/bbl)	45.13	52.47	59.42	44.50	46.68	34.52
NGLs ($/bbl)	17.23	25.09	24.56	15.56	8.47	18.18
Total ($/boe)	21.40	29.43	26.97	21.06	19.32	18.18
Hedging gain ($/boe)	4.98	5.18	0.99	4.06	6.87	7.84
Total realized ($/boe)	26.38	34.61	27.96	25.12	26.19	26.02

Average benchmark prices	Twelve months ended Dec. 31, 2016	Twelve months ended Dec. 31, 2015	Three months ended Dec. 31, 2016	Three months ended Sept. 30, 2016	Three months ended Jun. 30, 2016	Three months ended Mar. 31, 2016
Natural gas						
AECO (C$/mcf)	2.19	2.69	3.09	2.21	1.45	1.84
Crude Oil						
Edm Lt. (C$/ bbl)	52.82	57.48	60.70	54.26	55.04	41.22
Foreign Exchange						
US$/C$	0.75	0.78	0.75	0.76	0.78	0.73

CASH FLOWS FROM OPERATING ACTIVITIES, FUNDS FROM OPERATIONS AND NET LOSS

In the fourth quarter of 2016 Petrus generated cash flows from operating activities of $18.8 million, compared to $8.8 million in the fourth quarter of 2015. For the year ended December 31, 2016, Petrus generated cash flows from operating activities (GAAP) of $41.9 million compared to $15.5 million in the prior year. The changes for the three and twelve month periods are explained by changes in non-cash working capital.

Petrus generated funds from operations of $10.3 million in the fourth quarter of 2016, a 54% increase relative to $6.7 million generated in the fourth quarter of 2015. The increase is due to higher production, lower operating expenses, and improved commodity prices. The increase was offset by $1.4 million of G&A expenses related to one-time severance costs and annual incentive compensation recognized in the fourth quarter of 2016. For the year ended December 31, 2016, Petrus generated funds from operations of $28.6 million which is 36% lower than $44.6 million in the prior year. The decrease on a full year basis is due to lower production (attributed to the Peace River asset disposition) and lower commodity prices, in addition to higher fourth quarter G&A expenses.

Petrus reported a net loss of $11.8 million in the fourth quarter of 2016, compared to a net loss of $36.4 million in the fourth quarter of the prior year. The net loss is lower in the fourth quarter of 2016 due to lower expenses incurred, as well as a $39.0 million impairment loss realized in the fourth quarter of the prior year. On a twelve month basis, the Company incurred a net loss of $67.0 million in 2016, compared to a net loss of $69.0 million in the comparable period of 2015. The reduced loss reported for the twelve month period ended December 31, 2016 is primarily due to higher impairment losses realized in 2015, which were offset by lower commodity prices and production volumes in 2016.

(000s except per share)	**Twelve months ended December 31, 2016**	Twelve months ended December 31, 2015	**Three months ended December 31, 2016**	Three months ended December 31, 2015
Funds from operations [(1)]	**28,568**	44,639	**10,317**	6,717
Funds from operations per share [(1)]	0.64	1.27	0.23	0.19
Net loss	**(66,988)**	(69,031)	**(11,842)**	(36,425)
Net loss per share	(1.51)	(1.96)	(0.26)	(1.04)
Common shares	45,349	35,148	45,349	35,148
Weighted average shares	44,429	35,148	45,349	35,148

(1) See "Non-GAAP Financial Measures in the MD&A."

OIL AND NATURAL GAS REVENUE

Average production for the fourth quarter of 2016 was 8,595 boe/d (72% natural gas), 5% higher than the 8,172 boe/d (64% natural gas) reported for the fourth quarter of the prior year. The increase is due to development drilling in the Ferrier area, offset by the divestiture of the Peace River area assets which closed early in the third quarter of 2016. Total oil and natural gas revenue for the fourth quarter increased from $20.5 million in 2015 to $21.4 million in 2016 due to higher production and higher commodity prices.

Average production for the year ended December 31, 2016 was 8,236 boe/d (69% natural gas) which is 6% lower than the 8,762 boe/d (61% natural gas) reported for the year ended December 31, 2015. The decrease in annual average production is due in part to the disposition of the Peace River assets in 2016. Total oil and natural gas revenue decreased from $94.6 million in 2015 to $64.8 million in 2016 due to lower commodity prices as well as lower production, including the effect of the divestiture of the Company's Peace River assets.

Natural gas

During the three and twelve month periods ended December 31, 2016, the average benchmark natural gas price in Canada (set at the AECO hub) increased by 18% and decreased by 23%, respectively, from the same periods in the prior year (average price of $3.09 per mcf in the fourth quarter of 2016 compared to $2.61 per mcf in the fourth quarter of the prior year and $2.19 per mcf for 2016, compared to $2.84 per mcf in 2015).

The Company's average realized natural gas price during the fourth quarter of 2016 was $3.29 per mcf, compared to $2.79 per mcf in the fourth quarter of 2015, which represents a 20% increase. Natural gas revenue for the fourth quarter of 2016 was $11.3 million and production of 3,434,084 mcf accounted for approximately 72% of fourth quarter production volume and 53% of oil and natural gas revenue (compared to revenue of $8.0 million and production of 2,871,932 mcf for 64% of production volume and 40% of oil and natural gas revenue in the prior year comparative period). Natural gas revenue increased from the prior year due to increased commodity prices during the second half of 2016 and continued growth in production in the Ferrier area.

Natural gas revenue for the year ended December 31, 2016 was $29.7 million and production of 12,430,937 mcf accounted for approximately 69% of production volume for the year and 46% of oil and natural gas revenue, compared to revenue of $34.3 million and production of 11,712,014 mcf for 61% of production volume and 36% of oil and natural gas revenue in 2015. The decrease in natural gas revenue was due to the decline in commodity prices during the first half of 2016, offset by the commodity price recovery in the second half of 2016 and increased production in the Ferrier area.

Crude oil and condensate

Edmonton Light Sweet crude oil prices increased 16% from the fourth quarter of 2015 to the fourth quarter of 2016 (an average price of $60.70 per bbl for the fourth quarter of 2016 compared to an average price of $52.52 per bbl for the prior year comparative period). Prices decreased 8% from the year-ended December 31, 2015 to the year-ended December 31, 2016 ($52.82 per bbl for 2016 compared to an average price of $57.48 per bbl for 2015).

The average realized price of Petrus' crude oil and condensate was $59.42 per bbl for the fourth quarter of 2016 compared to $48.27 per bbl for the same period in the prior year. For the year-ended December 31, 2016, the average realized price of Petrus' crude oil and condensate was $45.13 per bbl compared to $52.47 per bbl for the same period in 2015.

Oil and condensate revenue for the fourth quarter of 2016 was $7.9 million and production of 133,603 bbl accounted for approximately 17% of total production volume and 37% of oil and natural gas revenue, compared to revenue of $10.6 million and production of 218,902 bbl for 29% of total production volume and 52% of oil and natural gas revenue in the fourth quarter of the prior year.

Oil and condensate revenue for the year-ended December 31, 2016 was $30.1 million and production of 666,127 bbl accounted for approximately 22% of total production volume and 46% of oil and natural gas revenue, compared to revenue of $54.6 million and production of 1,035,719 bbl for 32% of total production volume and 58% of oil and natural gas revenue in 2015.

Oil and condensate revenue decreased from the prior year as a result of the decline in commodity prices and production volumes (due in part to asset dispositions).

Natural gas liquids (NGLs)

The Company's NGL production mix consists of ethane, propane, butane, pentane and sulphur. The pricing received for NGL production is based on the product mix, the fractionation process required and the demand for fractionation facilities. In the fourth quarter of 2016, the overall realized NGL price averaged $24.56 per bbl, compared to $30.52 per bbl in the prior year. For the year-ended December 31, 2016, the overall realized NGL price averaged $17.23 per bbl, compared to $24.56 per bbl in the prior year.

NGL revenue for the fourth quarter of 2016 was $2.1 million and production of 84,855 bbl accounted for approximately 11% of production volume and 10% of oil and natural gas revenue in the fourth quarter, compared to revenue of $1.7 million and production of 54,288 bbl for 7% of production volume and 7% of oil and natural gas revenue for the fourth quarter of the prior year. NGL revenue for the year-ended December 31, 2016 was $4.8 million and cumulative production of 276,398 bbls accounted for approximately 9% of cumulative production volumes and 7% of oil and natural gas revenue during the year, compared to revenue of $5.3 million and cumulative production of 210,314 bbl for 7% of production volumes and 6% of oil and natural gas revenue in the first twelve months of the prior year.

The decrease in the 2016 NGL revenue was due to the decline in commodity prices during the first half of 2016, while the increase in NGL revenue for the fourth quarter of 2016 was due to the increase in production and commodity prices during the second half of 2016.

Royalty Revenue

Petrus records gross overriding royalty revenue for its royalty interest production from its land or mineral rights owned. Petrus received royalty revenue in the fourth quarter of 2016 of $0.08 million compared to $0.2 million in the same quarter of the prior year. For the year ended December 31, 2016, Petrus earned $0.3 million, a decrease of 27% from $0.5 million earned in the year ended December 31, 2015. The decrease is attributed to lower commodity prices and production in the first half of 2016.

ROYALTY EXPENSES

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

Royalty Expenses ($000s)	**Twelve months ended December 31, 2016**	Twelve months ended December 31, 2015	**Three months ended December 31, 2016**	Three months ended December 31, 2015
Crown	**3,901**	6,097	**1,920**	1,771
% of production revenue	**6%**	6%	**9%**	9%
Gross overriding	**5,046**	5,865	**1,230**	1,038
Total	**8,947**	**11,962**	**3,150**	**2,809**

Total royalty expenses (net of royalty allowances and incentives) increased from $2.8 million in the fourth quarter of 2015 to $3.2 million in the fourth quarter of 2016. The increase was attributable to higher commodity prices and production. On a twelve month basis, total royalties paid decreased from $12.0 million in 2015 to $8.9 million in 2016. The decrease was the result of lower royalties paid due to lower commodity prices and lower production during the first three quarters of 2016 as well as higher royalty allowances and incentives compared to the prior year.

Gross overriding royalties increased from $1.0 million in the fourth quarter of 2015 to $1.2 million in the fourth quarter of 2016 due to additional wells being drilled on land with gross overriding royalty burdens. The gross overriding royalties decreased from $5.9 million in 2015 to $5.0 million in 2016. The decrease is due primarily to lower commodity prices.

RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility, increase the certainty of cash flows from operating activities and to protect acquisition and development economics. Petrus' risk management program is governed by guidelines approved by its Board of Directors. Petrus aims to hedge 60 to 70% of its 12 month production forecast and 30 to 40% of the following year production forecast.

The impact of the contracts which were outstanding during the reporting periods are actual cash settlements and are recorded as realized hedging gains (losses). These affect the Company's realized commodity price. 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)	**Twelve months ended December 31, 2016**	Twelve months ended December 31, 2015	**Three months ended December 31, 2016**	Three months ended December 31, 2015
Realized hedging gain	**15,002**	16,563	**783**	5,020
Unrealized hedging gain (loss)	**(21,531)**	(479)	**(9,225)**	3,363
Total gain (loss) on derivatives	**(6,529)**	**16,084**	**(8,442)**	**8,383**

Strengthening commodity prices resulted in a realized hedging gain of $0.8 million during the fourth quarter of 2016, compared to a $5.0 million gain realized in the same quarter of the prior year. The fourth quarter realized gain increased the Company's total realized price by $0.99 per boe, compared to an increase of $6.68 per boe in the fourth quarter of the prior year. For the year ended December 31, 2016, Petrus recorded a $15.0 million realized gain on financial derivatives compared to a $16.6 million realized gain recorded in the prior year.

The unrealized hedging loss of $9.2 million for the three months ended December 31, 2016, represents the change in the unrealized risk management net asset position during the quarter. This change is the result of both the realization of hedging gains in the quarter, changes related to contracts entered into during the quarter as well as changes to commodity prices. On December 31, 2016, the unrealized risk management net liability mark-to-market value was $7.6 million.

The Company's risk management contracts provide protection from crude oil and natural gas prices in 2017 and 2018. For a complete listing of Petrus' risk management contracts see the Company's December 31, 2016 annual consolidated financial statements (note 10). The table below summarizes Petrus' average crude oil and natural gas hedged volumes. The 1,350 bbl/d of oil hedged in the fourth quarter of 2016 represents 64% of fourth quarter average liquids (oil and NGL) production. The 22,200 GJ per day of natural gas hedged in the fourth quarter of 2016 represents 63% of fourth quarter average natural gas production.

	2017					**2018**				
	Q1	**Q2**	**Q3**	**Q4**	**Avg.**	**Q1**	**Q2**	**Q3**	**Q4**	**Avg.**
Oil hedged (bbl/d)	1,500	1,400	1,250	1,150	**1,325**	800	500	400	—	**425**
Average WTI cap price (C$/bbl)	74.99	71.69	67.34	71.85	**71.47**	70.03	72.03	70.85	—	**70.97**
Average WTI floor price (C$/bbl)	68.42	65.74	62.82	63.66	**65.16**	60.23	69.92	70.85	—	**67.00**
Natural gas hedged (GJ/d)	23,000	20,650	20,650	18,550	**20,713**	15,500	10,000	10,000	3,333	**9,708**
Average AECO cap price (C$/GJ)	3.18	2.71	2.71	2.93	**2.88**	3.05	2.43	2.43	2.43	**2.62**
Average AECO floor price (C$/GJ)	2.96	2.68	2.68	2.88	**2.80**	2.98	2.43	2.43	2.43	**2.60**

OPERATING EXPENSES

The following table shows the Company's operating expenses for the reporting periods which are shown net of processing income and overhead recoveries:

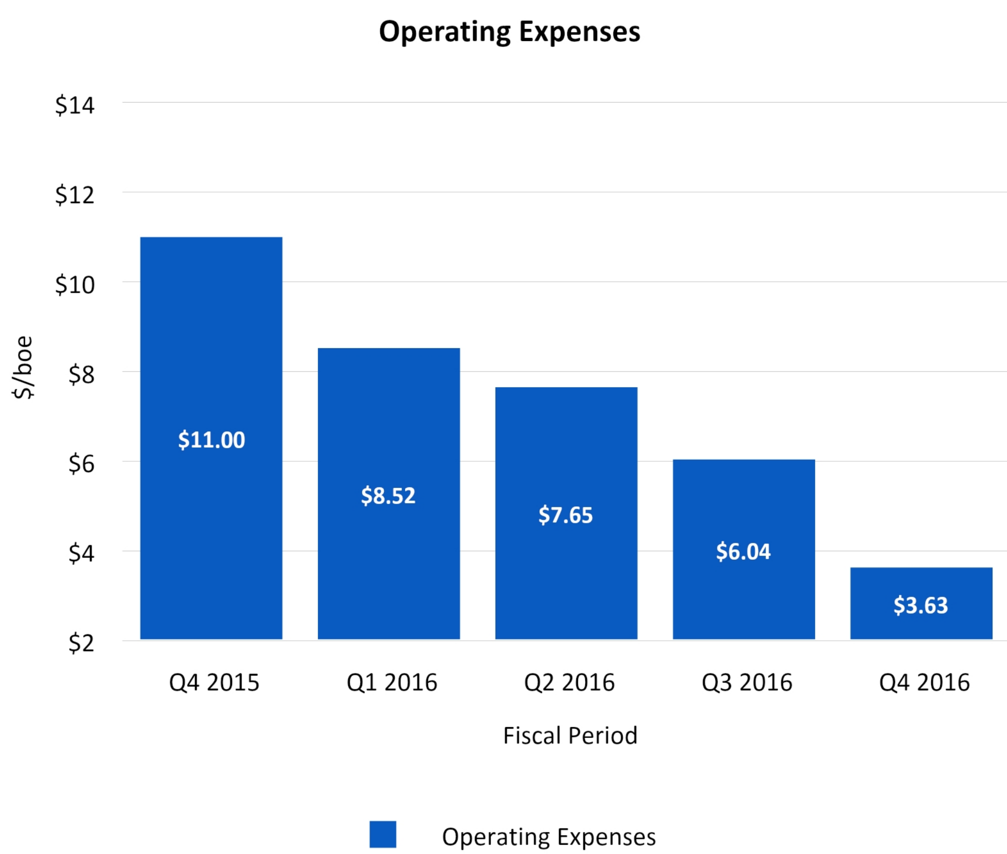
Operating Expenses ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Operating expense, net [1]	**19,522**	28,478	**2,867**	8,269
Operating expense, net ($ per boe)	**6.48**	8.90	**3.63**	11.00

[1] *Operating expenses are presented net of processing income and overhead recoveries*

Operating expenses (presented net of processing income and overhead recoveries) totaled $2.9 million for the fourth quarter of 2016, a 65% decrease from $8.3 million recorded in the fourth quarter of the prior year. The decrease is attributable to investments in facilities designed to reduce third party processing fees. The divestiture of Petrus' Peace River assets and processing income generated from third parties contributed to the lower net operating expenses. On a per boe basis, operating expenses were $3.63 in the fourth quarter, which was 67% lower than the $11.00 per boe incurred in the fourth quarter of the prior year.

For the year ended December 31, 2016, operating expenses totaled $19.5 million ($6.48 per boe) and $28.5 million ($8.90 per boe) in 2015. The 27% decrease on a per boe basis is attributable to investment in facilities designed to reduce operating costs as well as the divestiture of assets with a higher production cost structure.

As shown in the graph below, the Company made significant changes throughout 2016 to its production cost structure and realized material reductions in operating expenses. The Company continued its focus on reducing operating expenses in Ferrier, which contributed to the decrease in operating expenses on a per boe basis. The Company also strategically divested assets with higher production costs, which further accelerated the declining cost structure.



TRANSPORTATION EXPENSES

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

Transportation Expenses ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Transportation expense	**4,457**	5,250	**1,187**	986
Transportation expense ($ per boe)	**1.48**	1.64	**1.50**	1.31

Petrus pays commodity and demand charges for transporting its gas on various pipeline systems. The Company also incurs trucking costs on the portion of its oil and natural gas liquids production that is not pipeline connected. Transportation expenses totaled $1.2 million or $1.50 per boe in the fourth quarter of 2016 ($1.0 million or $1.31 per boe for the comparative period of 2015). The increase in transportation expenses for the three month period is attributable to increased market transportation rates. On a twelve month basis transportation expenses totaled $4.5 million in 2016 ($1.48 per boe) and $5.2 million ($1.64 per boe) in 2015. The reduction in transportation expenses for the twelve month period is attributable to asset divestitures.

GENERAL AND ADMINISTRATIVE EXPENSES

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

General and Administrative Expenses ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Gross general and administrative expense	**10,165**	9,168	**4,283**	2,470
Capitalized general and administrative	**(2,459)**	(1,668)	**(1,292)**	(152)
General and administrative expense	**7,706**	**7,500**	**2,991**	**2,318**
General and administrative ($ per boe)	**2.56**	**2.35**	**3.78**	**3.08**

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

General and Administrative Expenses ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Personnel, consultants and directors	**6,593**	4,554	**3,285**	1,167
Regulatory expenses	**1,017**	161	**375**	74
Office costs	**2,130**	2,533	**607**	1,033
Subscriptions & licenses	**137**	10	**4**	10
Public company expenses	**248**	1,697	**—**	—
Transaction costs	**39**	213	**11**	187
Capitalized general and administrative	**(2,458)**	(1,668)	**(1,291)**	(152)
Total general and administrative expense	**7,706**	**7,500**	**2,991**	**2,318**

Fourth quarter 2016 general and administrative expense totaled $3.0 million or $3.78 per boe (compared to $2.3 million or $3.08 per boe in the fourth quarter of 2015). The increase was due to $1.4 million higher costs incurred related to one time severance costs combined with annual incentive compensation recognized in the fourth quarter.

General and administrative expense for the year ended December 31, 2016 totaled $7.7 million ($2.56 per boe) compared to $7.5 million ($2.35 per boe) for the year ended December 31, 2015. Base salaries and consulting fees were lower in 2016 compared to the prior year due to staff and cost reduction initiatives; however, one-time severance costs and annual incentive compensation totaling $1.4 million were recognized in the fourth quarter of 2016.

G&A costs capitalized (directly attributable to the acquisition, exploration and development activities of the Company) are quantified in the table above.

SHARE-BASED COMPENSATION EXPENSE

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

Share-Based Compensation Expense ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Gross share-based compensation expense	789	1,175	267	239
Capitalized share-based compensation	(262)	(520)	(53)	(165)
Share-based compensation expense	527	655	214	74

Share-based compensation expense (net of capitalized portion) increased from $0.1 million in the fourth quarter of 2015 to $0.2 million in the fourth quarter of 2016. The increase is attributed to a stock option grant on November 17, 2016.

Share-based compensation expense (net of capitalized portion) decreased from $0.7 million in 2015 to $0.5 million in 2016. The decrease is due to the expiry of certain performance warrants and stock options which resulted in lower share-based compensation expense incurred in 2016.

FINANCE EXPENSE

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

Finance Expense ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Interest expense	10,587	13,366	2,043	4,510
Foreign exchange loss (gain)	50	(567)	—	—
Total cash finance expenses	10,637	12,799	2,043	4,510
Deferred financing costs	—	1,261	—	—
Accretion on decommissioning obligations	973	1,216	47	353
Total finance expense	11,610	15,276	2,090	4,863

The Company incurred total finance expense of $2.1 million in the fourth quarter of 2016, comprised of $0.05 million of non-cash accretion of its decommissioning obligation and $2.0 million of cash interest expense related to its credit facilities and term loan. In the fourth quarter of 2015, the Company incurred total finance expense of $4.9 million, comprised of $4.5 million cash interest expense and $0.4 million in non-cash accretion of its decommissioning obligation. The significant decrease in 2016 is due to lower debt outstanding as a result of financing proceeds and the Peace River asset disposition proceeds used to repay bank indebtedness. On a twelve month basis, finance expense decreased 24% from $15.3 million in 2015 to $11.6 million in 2016. The decrease is due to lower cash interest costs attributed to lower bank indebtedness. Lower non-cash finance expense in 2016 (deferred financing cost and accretion on decommissioning obligation) contributed to the decrease.

DEPLETION AND DEPRECIATION

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

Depletion and Depreciation ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Depletion	46,149	54,410	11,736	12,163
Depreciation	112	217	29	44
Total	46,261	54,627	11,765	12,207
Depletion ($ per boe)	15.31	17.01	14.84	15.22
Depreciation ($ per boe)	0.04	0.07	0.04	0.06
Total ($ per boe)	15.35	17.08	14.88	15.28

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.

Petrus recorded depletion expense in the fourth quarter of 2016 of $11.7 million or $14.84 per boe, compared to the fourth quarter of 2015, when $12.2 million or $15.22 per boe was recorded. On a twelve month basis, depletion expense was $46.1 million ($15.31 per boe) in 2016 and $54.4

million ($17.01 per boe) in 2015. On a three and twelve month basis, depletion expense decreased from the comparable periods of the prior year due to the divestiture of the Peace River assets. Depreciation expense is not significant as most depreciable assets were fully depreciated in the prior year.

IMPAIRMENT

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

Impairment ($000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Impairment	**25,000**	67,494	**—**	38,954
Total	**25,000**	**67,494**	**—**	**38,954**

Petrus did not recognize an impairment loss in the three months ended December 31, 2016. In the three months ended December 31, 2015, an impairment loss of $39.0 million was recorded. Petrus recorded an impairment loss of $25.0 million in the year ended December 31, 2016 in conjunction with classification of certain assets located in the Peace River area of Alberta as assets held for sale disposition closed during the third quarter of 2016. The impairment loss of $67.5 million recognized during the year ended December 31, 2015 was due to a decrease in forward commodity prices and, at the time, recent transaction metrics.

SHARE CAPITAL

The authorized share capital consists of an unlimited number of Common Shares. The following table details the number of issued and outstanding securities for the periods shown:

Share Capital (000s)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Three months ended December 31, 2016	Three months ended December 31, 2015
Weighted average outstanding common shares				
Basic	**44,429**	35,148	**45,349**	35,148
Diluted	**44,429**	35,148	**45,349**	35,148
Outstanding instruments				
Common shares	**45,349**	35,148	**45,349**	35,148
Stock options	**1,977**	1,454	**1,977**	1,454
Performance warrants	**430**	1,569	**430**	1,569

At December 31, 2016, the Company had 45,349,192 Common Shares, 1,976,580 stock options and 429,667 performance warrants outstanding. On February 28, 2017, the Company closed the Private Placement of 4,078,708 Common Shares at a purchase price of $2.53 per Common Share, for aggregate gross proceeds of $10.3 million.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2016 Petrus had two debt instruments outstanding. The first is a reserve-based, revolving credit facility with a syndicate of lenders. The total facility is comprised of an operating facility and a syndicated term-out facility (together the “Revolving Credit Facility” or “RCF”). The second is a second lien term loan (the “Term Loan”).

(a) Revolving Credit Facility

At December 31, 2016 the Company’s RCF was comprised of a $20 million operating facility and a $86 million syndicated term-out facility. The term-out facility has a revolving period that ends July 29, 2017 at which time it will either be renewed or converted to a one-year term facility. The Company has provided collateral by way of a $600 million debenture over all of the present and after acquired property of the Company.

At December 31, 2016, the Company had a $0.3 million letter of credit outstanding against the RCF (December 31, 2015 – $2.4 million) and had drawn $73.8 million against the RCF (December 31, 2015 – $145 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.

(b) Term Loan

At December 31, 2016 the Company had a $42 million (December 31, 2015 – $90 million) Term Loan outstanding which was due October 8, 2017. The Term Loan bears interest is due and payable monthly and accrues at a per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points.

Covenants

The RCF and the Term Loan carry covenants that are defined in note 8 to the December 31, 2016 consolidated financial statements. The Company is in compliance with all covenants at December 31, 2016.

Subsequent Events

On January 24, 2017 Petrus entered into an agreement with Macquarie Bank Limited to extend the Company's $42 million Term Loan by two years, now due October 2019. Concurrent with the extension, the Company reduced the amount outstanding by $7 million through working capital and available credit facilities. The interest rate on the $35 million balance remains unchanged at per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points.

On February 28, 2017 the Company closed a non-brokered private placement of 4,078,708 common shares of the Company ("Common Shares") at a purchase price of $2.53 per Common Share, for aggregate gross proceeds of $10.3 million (the "Private Placement"). A portion of the net proceeds of the Private Placement were used to fund the Acquisition and Petrus expects the remainder will be used to fund the Company's 2017 capital program.

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 accounts payable, long term debt and risk management liabilities. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future cash flows.

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

As at December 31, 2016, the Company had a working capital deficiency of $56.8 million, primarily related to the $42 million Term Loan due on October 8, 2017. Subsequent to December 31, 2016, the working capital deficiency was reduced as the Company entered into an agreement to extend the Term Loan by two years and also reduced the amount outstanding on its Term Loan by $7 million. The Company plans to address any remaining working capital deficiency by using its cash flows from operating activities and available credit facilities.

Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through its cash flows from operating activities and available credit capacity on its RCF. The Company is exposed to the risk of reductions to its borrowing base for purposes of the RCF or Term Loan. Petrus completed its semi-annual review of its revolving credit facility on October 31, 2016, whereby the syndicate of lenders unanimously agreed to maintain the facility at $106 million. Lender consent is required for total borrowings against the RCF exceeding $100.5 million. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2017. The Company believes that it will have adequate cash flows from operating activities to satisfy its financial liabilities with respect to its bank debt.

The following are the contractual maturities of financial liabilities as at December 31, 2016:

($000s)	**Total**	**< 1 year**	**1-5 years**	**> 5 years**
Accounts payable	22,066	22,066	—	—
Risk management liability	7,620	5,696	1,924	—
Revolving credit facility	73,767	—	73,767	—
Term loan	42,000	42,000	—	—
Total	**145,453**	**69,762**	**75,691**	—

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

($000s)	**Total**	**< 1 year**	**1-5 years**	**> 5 years**
Corporate office lease	2,240	749	1,491	—
Firm service transportation	7,505	815	4,074	2,617
Total commitments	**9,745**	**1,564**	**5,565**	**2,617**

Petrus Resources

Risk Management

Petrus is engaged in the development, acquisition, exploration and production 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 our business strategy. Financial risks associated with the petroleum 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 further and more in-depth discussion of risk management, see the Company's annual consolidated financial statements and the Company's Annual Information Form for the year ended December 31, 2016.

CAPITAL EXPENDITURES

Capital expenditures totaled $10.0 million in the fourth quarter of 2016, compared to $6.8 million in the fourth quarter of the prior year (excluding acquisitions and dispositions). In the twelve month period ended December 31, 2016, Petrus invested $29.2 million in capital expenditures, compared to $54.5 million in the prior year. During this twelve month period, Petrus invested in the drilling, completion and tie-in of 11 (7.3 net) liquids rich natural gas wells in the Ferrier area along with infrastructure and facility investment also in the Ferrier area. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations.

Capital Expenditures ($000s)	**Twelve months ended December 31, 2016**	Twelve months ended December 31, 2015	**Three months ended December 31, 2016**	Three months ended December 31, 2015
Drill and complete	**17,460**	30,313	**6,071**	2,117
Oil and gas equipment	**8,918**	21,853	**2,413**	4,262
Geological	**2**	302	**2**	—
Land and lease	**350**	106	**191**	—
Office	**—**	227	**—**	—
Capitalized general and administrative	**2,516**	1,668	**1,349**	378
Total Capital Expenditures	**29,246**	**54,469**	**10,026**	**6,757**
Gross (net) wells spud	**11 (7.3)**	**5 (4.7)**	**5 (2.6)**	**—**

During the year ended December 31, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.5 million after post-closing adjustments, comprised of $28.5 million in cash and 1.0 million shares of the purchaser. Also during the year Petrus closed a property swap transaction disposing of non-core assets in its Foothills area for assets in its Ferrier core area for the swap assets and completed other minor dispositions of non-core exploration and evaluation assets and petroleum and natural gas properties and equipment for total cash consideration of $0.5 million. The net of all acquisition and disposition activity was $29.4 million net disposition for the year ended December 31, 2016 ($0.9 million net acquisitions in 2015) and $0.4 million net acquisition for the three months ended December 31, 2016 ($Nil for the three months ended December 31, 2015). For additional information refer to Note 5 of the Company's consolidated financial statements for the year-ended December 31, 2016.

Acquisitions/(dispositions) ($000s)	**Twelve months ended December 31, 2016**	Twelve months ended December 31, 2015	**Three months ended December 31, 2016**	Three months ended December 31, 2015
Acquisitions/(dispositions)	**(29,717)**	938	—	—

SELECTED ANNUAL INFORMATION

FINANCIAL (000s except per share)	Twelve months ended December 31, 2016	Twelve months ended December 31, 2015	Twelve months ended December 31, 2014
Total average production (boe/d)	8,236	8,762	6,032
Oil and natural gas revenue	64,840	94,587	112,705
Net loss	(66,988)	(69,031)	(47,492)
Net loss per share			
Basic	(1.51)	(1.96)	(1.78)
Fully diluted [3]	(1.51)	(1.96)	(1.78)
Funds from operations[1]	28,568	44,639	61,250
Funds from operations per share [1]			
Basic	0.64	1.27	2.30
Fully diluted [2]	0.64	1.27	2.30
Total assets	439,967	555,145	647,304
Net debt [1]	124,915	226,742	215,048
Weighted average shares outstanding (000s)			
Basic	44,429	35,148	26,680
Fully diluted [2]	44,429	35,148	26,680

[1] *See "Non-GAAP Financial Measures in the MD&A."*

[2] *In computing diluted per share metrics no instruments (performance warrants or stock options) were added to the calculation as their impact is anti-dilutive.*

SUMMARY OF QUARTERLY RESULTS

	Three months ended							
(000s) except per share & boe amounts	**Dec. 31, 2016**	**Sep. 30, 2016**	**Jun. 30, 2016**	**Mar. 31, 2016**	**Dec. 31, 2015**	**Sep. 30, 2015**	**Jun. 30, 2015**	**Mar. 31, 2015**
Average Production								
Natural gas (mcf/d)	37,327	30,009	33,071	35,456	31,217	32,505	31,103	31,525
Oil (bbl/d)	1,452	1,419	2,200	2,218	2,380	2,616	2,811	3,559
NGLs (bbl/d)	922	680	723	694	590	634	560	519
Total (boe/d)	**8,595**	**7,100**	**8,435**	**8,821**	**8,172**	**8,668**	**8,890**	**9,333**
Total (boe)	**790,806**	**653,215**	**767,585**	**802,744**	**751,845**	**797,439**	**808,947**	**839,927**
Financial Results								
Oil and natural gas revenue	21,409	13,805	14,926	14,698	20,459	21,991	26,641	25,495
Royalty expense (1)	(2,787)	(1,951)	(1,734)	(2,475)	(2,809)	(2,308)	(3,020)	(3,825)
Net oil and natural gas revenue	**18,622**	**11,854**	**13,192**	**12,223**	**17,650**	**19,683**	**23,621**	**21,670**
Transportation	(1,187)	(971)	(1,000)	(1,298)	(986)	(1,142)	(1,561)	(1,560)
Operating expense	(2,867)	(3,945)	(5,872)	(6,837)	(8,269)	(6,277)	(7,396)	(6,536)
Operating netback (2)	**14,568**	**6,938**	**6,320**	**4,088**	**8,395**	**12,264**	**14,664**	**13,574**
Realized gain (loss) on derivatives	783	2,652	5,273	6,294	5,020	3,767	2,894	4,881
General & administrative expense	(2,991)	(1,107)	(1,426)	(2,183)	(2,318)	(1,674)	(1,843)	(1,664)
Cash finance expense	(2,043)	(2,512)	(2,442)	(3,641)	(4,510)	(3,519)	(3,166)	(2,256)
Corporate netback (2)	**10,317**	**5,971**	**7,725**	**4,558**	**6,587**	**10,838**	**12,549**	**14,535**
Oil and natural gas revenue	**21,409**	**13,805**	**14,926**	**14,698**	**20,459**	**21,991**	**26,641**	**25,495**
Per share - basic	0.48	304.42	329.14	351.95	582.08	625.67	757.97	725.36
Per share - fully diluted (3)	0.48	304.42	329.14	351.95	582.08	625.67	757.97	725.36
Net loss	**(11,842)**	**(4,702)**	**(46,334)**	**(4,110)**	**(36,425)**	**(19,055)**	**(7,239)**	**(6,312)**
Per share - basic	(0.27)	(0.10)	(1.02)	(0.10)	(1.04)	(0.54)	(0.21)	(0.18)
Per share - fully diluted (3)	(0.27)	(0.10)	(1.02)	(0.10)	(1.04)	(0.54)	(0.21)	(0.18)
Common shares outstanding								
Basic	45,349	45,349	45,349	45,349	35,148	35,148	35,148	35,148
Fully diluted (3)	45,349	45,349	45,349	45,349	35,148	35,148	35,148	35,148
Weighted average shares (3)	**44,429**	**45,349**	**45,349**	**41,762**	**35,148**	**35,148**	**35,148**	**35,148**
Total assets	439,967	448,404	493,535	544,548	555,145	595,890	627,808	641,547
Net debt (2)	**(124,915)**	**(124,310)**	**(152,935)**	**(157,675)**	**(226,742)**	**(226,809)**	**(228,562)**	**(227,607)**

(1) The Company re-classified gross overriding royalty expense from other income to royalty expenses in the Statement of Net Loss and Comprehensive Loss. The comparative information has been re-classified to conform to current presentation.

(2) See "Non-GAAP Financial Measures in the MD&A."

(3) In computing diluted per share metrics no instruments (performance warrants or stock options) were added to the calculation as their impact is anti-dilutive.

The oil and natural gas exploration and production industry is cyclical in nature. Petrus' financial position, results of operations and cash flows are affected by commodity prices, exchange rates, Canadian price differentials and production levels. Petrus' average quarterly production has decreased from 9,333 boe/d in the first quarter of 2015 to 8,595 boe/d in the fourth quarter of 2016. The production decline is attributable to natural production declines in addition to the disposition of the Company's assets in the Peace River area.

The Company's total oil and natural gas revenue was $25.5 million in the first quarter of 2015 and $21.4 million in the fourth quarter of 2016. Total oil and natural gas revenue has decreased due to lower production volume and a decrease in commodity prices over the two year period. Commodity price improvements enable higher reinvestment in exploration, development and acquisition activities in future periods as they increase the cash flows from operating activities. Commodity price reductions reduce revenues received and can challenge the economics of the Corporation's development program as the quantity of reserves may not be economically recoverable. Petrus' investment in its assets, and its ability to replace and grow reserve volumes, will be dependent on its ability to obtain debt and equity financing as well as the funds it receives from operations.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below.

Depletion and reserve estimates
Petroleum and natural gas assets are depleted on a unit of production basis at a rate calculated by reference to proven 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 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, petroleum and natural gas assets are aggregated into cash-generating units ("CGU's"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGU's 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 values less costs to sell. 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 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.

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. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable income available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in income or loss in the period in which the change occurs. Additionally, future 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.

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

Business combinations

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

Contingencies

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

OTHER FINANCIAL INFORMATION

Significant accounting policies

The Company's significant accounting policies can be read in Note 3 to the Company's audited financial statements as at and for the year ended December 31, 2016.

New standards and interpretations

IFRS 9 Financial Instruments

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted. IFRS 9 will be applied by Petrus on January 1, 2018. IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in OCI rather than the statement of operations, unless this creates an accounting mismatch. Based on its preliminary assessment, the Company does not anticipate these changes to have a material impact on its consolidated financial statements.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The new model will result in more timely recognition of expected credit losses. Petrus does not anticipate the new impairment model to have a material impact on the consolidated financial statements. IFRS 9 also contains a new model to be applied for hedge accounting, aligning hedge accounting more closely with risk management. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

IFRS 15 Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. This standards applies to new contracts dated on or after the effective date and to existing contracts not yet completed as of the effective date. IFRS 15 will be applied by Petrus on January 1, 2018. The Company will not early adopt this standard. The Company has identified all existing customer contracts that are within the scope of the new guidance and has begun to analyze individual contracts or groups of contracts to identify any significant differences and the impact on revenues as a result of implementing the new standard. As the Company continues its contract analysis, it will also quantify the impact, if any, on prior period revenues. The Company will address any system and process changes necessary to compile the information to meet the disclosure requirements of the new standard. As the Company is currently evaluating the impact of this standard, it has not yet determined the effect on its consolidated financial statements.

IAS 7 Disclosure Initiative – Amendments to IAS 7

Effective for annual periods beginning on or after January 1, 2017. The amendments to IAS 7 Statement of Cash Flows require disclosure that enable financial statement users to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. On initial application of the amendment, entities are not required to provide comparative information for preceding periods.

IFRS 16 Leases

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

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

IFRS 16 is effective for annual periods beginning on or after 1 January 2019. Early application is permitted, but not before an entity applies IFRS 15. 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. In 2017, Petrus plans to assess the potential effect of IFRS 16 on its consolidated financial statements.

Disclosure Controls and Procedures

Petrus' Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Chief Executive Officer and Chief Financial Officer of Petrus have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2016 and have concluded that the Company's DC&P are effective at December 31, 2016 for the foregoing purposes.

Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect 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, 2016, 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, 2016. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as at December 31, 2016, 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 news release makes reference to the terms "funds from operations," "funds from operations per share," "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 as set forth below.

Funds from operations

Funds from operations is used by management for its own performance measures and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate cash to fund all or a portion of its future growth and/or to repay debt. The most directly comparable GAAP measure to funds from operations is cash flow from operating activities (as per the Company's statement of cash flows in accordance with GAAP) and is calculated as cash flows from operating activities before non-cash changes in working capital and before spending on decommissioning obligations.

	Twelve months ended December 31, 2016		Twelve months ended December 31, 2015		**Three months ended December 31, 2016**		Three months ended December 31, 2015	
	$000s	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**	**$000s**	**$/boe**
Oil and natural gas revenue	64,840	21.51	94,587	29.57	21,409	27.07	20,459	27.22
Royalty expense	(8,947)	(2.97)	(11,962)	(3.74)	(2,787)	(3.52)	(2,809)	(3.74)
Net oil and natural gas revenue	**55,893**	**18.54**	**82,625**	**25.83**	**18,622**	**23.55**	**17,650**	**23.48**
Transportation expense	(4,457)	(1.48)	(5,250)	(1.64)	(1,187)	(1.50)	(986)	(1.31)
Operating expense	(19,522)	(6.48)	(28,478)	(8.90)	(2,867)	(3.63)	(8,269)	(11.00)
Operating netback	**31,914**	**10.58**	**131,522**	**41.12**	**14,568**	**18.42**	**8,395**	**11.17**
Realized gain on financial derivatives	15,002	4.98	16,563	5.18	783	0.99	5,020	6.68
General & administrative expense	(7,706)	(2.56)	(7,500)	(2.35)	(2,991)	(3.78)	(2,318)	(3.08)
Cash finance expense	(10,642)	(3.53)	(13,321)	(4.16)	(2,043)	(2.58)	(4,380)	(5.83)
Corporate netback	**28,568**	**9.47**	**127,264**	**39.79**	**10,317**	**13.05**	**6,717**	**8.94**

Operating netback

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

Corporate netback

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

Net Debt

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

($000s)	**As at December 31, 2016**	As at December 31, 2015
Current assets adjusted for unrealized financial instruments	**12,918**	20,097
Less: current liabilities adjusted for unrealized financial instruments	**(64,066)**	(141,839)
Less: long term debt	**(73,767)**	(105,000)
Net debt	**(124,915)**	**(226,742)**

Net Debt to Funds from Operations

Net debt to Funds from Operations is calculated as the period ending net debt divided by the trailing quarter funds from operations (annualized).

OIL AND GAS DISCLOSURES

Our oil and gas reserves statement for the year ended December 31, 2016, which includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form ("AIF") which will be available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

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

F&D and FD&A Costs

FD&A cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period. F&D cost is defined as capital costs for the time period including change in FDC divided by change in reserves including revisions and production for that same time period, excluding acquisitions and dispositions. Both F&D and FD&A costs take into account 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 2016, the P+P 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 the annualized fourth quarter production.

Reserve Replacement Ratio

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

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 Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are set out in the notes to the audited financial statements as at and for the twelve months ended December 31, 2016. 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 availability of cash flows from operating activities; expected processing and compression capacity at the Ferrier gas plant; sources of financing and the requirement therefor; and the Company's decline rate and the growth of Petrus; the treatment of the revolving facility following the end of the revolving period; Petrus' ability to fund its financial liabilities; the size of, and future net revenues from, crude oil, NGL (natural gas liquids) and natural gas reserves; future prospects; the focus of and timing of capital expenditures; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; access to debt and equity markets; projections of market prices and costs; the performance characteristics of the Company's crude oil, NGL and natural gas properties including estimated year end production; crude oil, NGL and natural gas production levels and product mix; Petrus' future operating and financial results; capital investment programs; supply and demand for crude oil, NGL and natural gas; future royalty rates; drilling, development and completion plans and the results therefrom; future land expiries; dispositions and joint venture arrangements; amount of operating, transportation and general and administrative expenses, including an expected decrease thereof; and treatment under governmental regulatory regimes and tax laws. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

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

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

BOE Presentation
The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent ("boe") basis whereby natural gas volumes are converted at the ratio of nine 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 equivalency of the two commodities at the burner tip. Boe's do not represent an economic value equivalency at the wellhead and therefore may be a misleading measure if used in isolation.

Abbreviations

000's	*thousand dollars*
bbl	*barrel*
bbl/d	*barrels per day*
bcf	*billion cubic feet*
boe/d	*barrel of oil equivalent per day*
CAD	*Canadian dollar*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
mbbls	*thousand barrels*
mboe	*thousand barrels of oil equivalent*
mcf	*thousand cubic feet*
mcf/d	*thousand cubic feet per day*
mmbbls	*million barrels*
mmboe	*millions of barrels of oil equivalent*
mmcf	*million cubic feet*
mmcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
USD	*United States dollar*
WTI	*West Texas Intermediate*

CONSOLIDATED ANNUAL FINANCIAL STATEMENTS

As at and for the years ended December 31, 2016 and 2015

INDEPENDENT AUDITORS' REPORT

To the Shareholders of **Petrus Resources Ltd.**

We have audited the accompanying consolidated financial statements of Petrus Resources Ltd., which comprise the consolidated balance sheets as at December 31, 2016 and 2015 and the consolidated statements of net loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, 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.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Petrus Resources Ltd. as at December 31, 2016 and 2015 and its financial performance and its cash flows for the years then ended, in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Calgary, Canada
March 8, 2017
Chartered Professional Accountants

CONSOLIDATED BALANCE SHEETS

(Expressed in 000's of Canadian dollars)

As at	December 31, 2016	December 31, 2015
ASSETS		
Current		
Cash	280	1,234
Deposits and prepaid expenses	1,111	1,109
Accounts receivable *(note 15)*	11,527	17,754
Risk management asset *(note 10)*	22	13,978
Total current assets	**12,940**	**34,075**
Non-current		
Exploration and evaluation assets *(notes 5 and 6)*	64,824	88,178
Property, plant and equipment *(notes 5 and 7)*	362,203	432,892
Total assets	**439,967**	**555,145**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Current portion of long term debt *(note 8)*	42,000	130,000
Accounts payable and accrued liabilities *(note 15)*	22,066	11,839
Risk management liability *(note 10)*	5,696	45
Total current liabilities	**69,762**	**141,884**
Non-current liabilities		
Long term debt *(note 8)*	73,767	105,000
Decommissioning obligation *(note 9)*	43,243	64,357
Risk management liability *(note 10)*	1,924	—
Total liabilities	**188,696**	**311,241**
Shareholders' equity		
Share capital *(note 11)*	419,671	346,106
Contributed surplus	7,410	6,620
Deficit	(175,810)	(108,822)
Total shareholders' equity	**251,271**	**243,904**
Total liabilities and shareholders' equity	**439,967**	**555,145**

Commitments (note 21)
Subsequent events (note 22)
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

(Expressed in 000's of Canadian dollars, except for share information)

	Year ended December 31, 2016	Year ended December 31, 2015
REVENUE		
Oil and natural gas revenue	**64,840**	**94,587**
Royalty expense	(8,947)	(11,962)
Net oil and natural gas revenue	**55,893**	**82,625**
Other income (expense)	(5)	105
Net gain (loss) on financial derivatives *(note 10)*	(6,529)	16,084
	49,359	**98,814**
EXPENSES		
Operating *(note 13)*	19,522	28,478
Transportation	4,457	5,250
General and administrative *(note 14)*	7,706	7,500
Share-based compensation *(note 11)*	527	655
Finance *(note 17)*	11,610	15,276
Exploration and evaluation *(note 6)*	2,426	6,275
Depletion and depreciation *(note 7)*	45,384	54,627
Loss (gain) on sale of assets *(note 5)*	(285)	53
Impairment *(notes 6 and 7)*	25,000	67,494
Total expenses	**116,347**	**185,608**
NET LOSS BEFORE INCOME TAXES	**(66,988)**	**(86,794)**
Deferred income tax recovery *(note 18)*	—	(17,763)
	—	**(17,763)**
NET LOSS AND COMPREHENSIVE LOSS	**(66,988)**	**(69,031)**
Net loss per common share		
Basic and diluted *(note 12)*	**(1.51)**	**(1.96)**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in 000's of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Total
Balance, December 31, 2014	**346,106**	**5,445**	**(39,791)**	**311,760**
Net loss	—	—	(69,031)	(69,031)
Share-based compensation	—	1,175	—	1,175
Balance, December 31, 2015	**346,106**	**6,620**	**(108,822)**	**243,904**
Net loss	—	—	(66,988)	(66,988)
Issuance of common shares *(note 11)*	75,488	—	—	75,488
Share issue costs *(note 11)*	(1,922)	—	—	(1,922)
Share-based compensation *(note 11)*	—	789	—	789
Balance, December 31, 2016	**419,672**	**7,410**	**(175,810)**	**251,271**

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Expressed in 000's of Canadian dollars)

Funds generated by (used in):	Year ended December 31, 2016	Year ended December 31, 2015
OPERATING ACTIVITIES		
Net loss	**(66,988)**	**(69,031)**
Adjust items not affecting cash:		
Share-based compensation *(note 11)*	527	655
Unrealized loss (gain) on financial derivatives (*note 10)*	21,531	479
Non-cash finance expenses *(note 17)*	973	1,851
Depletion and depreciation *(note 7)*	45,384	54,627
Impairment *(notes 6 and 7)*	25,000	67,494
Exploration and evaluation expense *(note 6)*	2,426	6,275
Loss (gain) on sale of assets *(note 5)*	(285)	52
Deferred income tax expense (recovery)	—	(17,763)
Funds from operations	**28,568**	**44,639**
Decommissioning expenditures *(note 9)*	(756)	(335)
Change in operating non-cash working capital *(note 19)*	14,041	(28,779)
Cash flows from operating activities	**41,853**	**15,525**
FINANCING ACTIVITIES		
Issue of common shares *(note 11)*	75,488	—
Share issue costs *(note 11)*	(1,922)	—
Repayment of term loan	(48,000)	—
Issuance (repayment) of revolving credit facility	(71,233)	45,290
Change in financing non-cash working capital *(note 19)*	323	458
Cash flows from (used in) financing activities	**(45,344)**	**45,748**
INVESTING ACTIVITIES		
Property and equipment dispositions (acquisitions) *(note 5)*	29,718	(938)
Exploration and evaluation asset expenditures *(note 6)*	(632)	(1,358)
Petroleum and natural gas property expenditures *(note 7)*	(28,614)	(53,111)
Change in investing non-cash working capital *(note 19)*	2,065	(24,156)
Cash flows from (used in) investing activities	**2,537**	**(79,563)**
Decrease in cash	(954)	(18,290)
Cash, beginning of year	1,234	19,524
Cash, end of year	**280**	**1,234**
Cash interest paid	10,587	13,366

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2016 and 2015

1. NATURE OF THE ORGANIZATION

Petrus Acquisition Corp. ("New Petrus") was incorporated under the laws of the Province of Alberta on November 25, 2015. On February 2, 2016, New Petrus changed its name to Petrus Resources Ltd. ("Petrus" or the "Company"). The Company has two subsidiaries, Petrus Resources Corp. (formerly Petrus Resources Ltd. ("Old Petrus")) and Petrus Resources Inc. (formerly PhosCan Chemical Corp. ("PhosCan")).

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

On February 2, 2016, New Petrus closed an equity financing involving a $30 million private placement and an arrangement agreement (the "Arrangement Agreement") with PhosCan and Old Petrus. Pursuant to the Arrangement Agreement, Old Petrus shareholders exchanged their Old Petrus common shares for New Petrus common shares on the basis of 0.25 New Petrus common shares for each Old Petrus common share held, resulting in the issuance of approximately 4.1 million New Petrus shares.

At the time of the Arrangement Agreement, PhosCan did not have any assets or liabilities other than $45.5 million in cash. PhosCan shareholders exchanged their PhosCan common shares for New Petrus common shares on the basis of 0.0452672 New Petrus common shares for each PhosCan common share held, resulting in the issuance of approximately 6.1 million New Petrus common shares. This resulted in an increase to New Petrus' cash and shareholders' equity on a consolidated basis.

While New Petrus is the continuing legal entity, the economic substance of the Arrangement Agreement was two financings executed by Old Petrus. Accordingly Old Petrus is the continuing accounting entity following the Arrangement Agreement. These financial statements have therefore been presented on a continuity of interest basis, with the financial position, results of operations and cash flows for all periods before February 2, 2016 being those of Old Petrus.

Petrus' legal share capital is that of Old Petrus to February 2, 2016 and continues as that of Petrus after that date. Common shares, performance warrants and stock options have been adjusted retrospectively for all periods presented for the 0.25 to 1 consolidation of shares referred to above.

These consolidated financial statements report the year ended December 31, 2016 and comparative period and were approved by the Company's Audit Committee and Board of Directors on March 8, 2017.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

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

(b) Measurement Basis

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

(c) Consolidation

These audited consolidated financial statements include the accounts of Petrus and its 100% owned subsidiaries, Old Petrus and Phoscan. 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.

(d) Critical Accounting Estimates

The timely preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below.

Depletion and reserve estimates

Petroleum and natural gas assets are depleted on a unit of production basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The calculation incorporates the estimated future cost of developing and extracting those reserves. Proved and probable reserves are estimated using independent reservoir engineering reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Reserves estimates, although not reported as part of the Company's financial statements, can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion and depreciation, decommissioning liabilities, deferred taxes, asset impairments and business combinations. Independent reservoir engineers perform evaluations of the Company's petroleum and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable petroleum and natural gas reserves are based upon a number 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, 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 petroleum and natural gas assets. The Company monitors internal and external indicators of impairment relating to its tangible assets.

Technical feasibility and commercial viability of exploration and evaluation assets

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

Financial Instruments

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

Decommissioning obligation

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

Income taxes

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

Measurement of share-based compensation

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

Business combinations

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

Contingencies

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

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Revenue recognition

Revenue from the sale of petroleum and natural gas is recognized when volumes are delivered and title passes to an external party at contractual delivery points and are recorded gross of transportation charges incurred by the Company.

The costs associated with the delivery, including transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

(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 pre-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

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

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

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

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

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

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

(g) Financial instruments

Non-derivative financial instruments
Non-derivative financial instruments are comprised of cash, accounts receivables, deposits, accounts payable and long term debt. Non-derivative financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured based on their classification. The Company has made the following classifications:

- Cash and deposits are classified as held for trading.
- Accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method.
- Accounts payable and long term debt are classified as other liabilities and are measured at amortized cost using the effective interest method.

Risk Management Contracts

The Company enters into risk management contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Petrus has not designated its risk management contracts as effective hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all risk management contracts are classified as fair value through profit or loss and are recorded at fair value on the balance sheet with changes in fair value recorded in the statement of income (loss) and comprehensive income (loss). The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date.

(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.

(m) Earnings per share

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

(n) Leases

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

(o) New standards and interpretations

IFRS 9 Financial Instruments
In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018 with earlier adoption permitted. IFRS 9 will be applied by Petrus on January 1, 2018. IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in OCI rather than the statement of operations, unless this creates an accounting mismatch. Based on its preliminary assessment, the Company does not anticipate these changes to have a material impact on its consolidated financial statements.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The new model will result in more timely recognition of expected credit losses. Petrus does not anticipate the new impairment model to have a material impact on the consolidated financial statements. IFRS 9 also contains a new model to be applied for hedge accounting, aligning hedge accounting more closely with risk management. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

IFRS 15 Revenue from Contracts with Customers
In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. This standards applies to new contracts dated on or after the effective date and to existing contracts not yet completed as of the effective date. IFRS 15 will be applied by Petrus on January 1, 2018. The Company will not early adopt this standard. The Company has identified all existing customer contracts that are within the scope of the new guidance and has begun to analyze individual contracts or groups of contracts to identify any significant differences and the impact on revenues as a result of implementing the new standard. As the Company continues its contract analysis, it will also quantify the impact, if any, on prior period revenues. The Company will address any system and process changes necessary to compile the information to meet the disclosure requirements of the new standard. As the Company is currently evaluating the impact of this standard, it has not yet determined the effect on its consolidated financial statements.

IAS 7 Disclosure Initiative – Amendments to IAS 7
Effective for annual periods beginning on or after January 1, 2017. The amendments to IAS 7 Statement of Cash Flows require disclosure that enable financial statement users to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. On initial application of the amendment, entities are not required to provide comparative information for preceding periods.

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

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

IFRS 16 is effective for annual periods beginning on or after 1 January 2019. Early application is permitted, but not before an entity applies IFRS 15. 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. In 2017, Petrus plans to assess the potential effect of IFRS 16 on its consolidated financial statements.

4. DETERMINATION OF FAIR VALUES

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

Petroleum and natural gas properties and equipment and exploration and evaluation assets
The fair value of petroleum and natural gas properties and equipment recognized in a business combination and for impairment testing, is based on market values. The market value of petroleum and natural gas properties and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in petroleum and natural gas properties and equipment) and intangible exploration and evaluation assets is estimated with reference to

the discounted cash flow expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The fair value less costs of disposal value used to determine the recoverable amount of the impaired petroleum and natural gas properties are classified as Level 3 fair value measurements. Refer to *"Financial Instruments"* section below for fair value hierarchy classifications.

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

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

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

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

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

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

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The Company's cash and deposits are considered Level 1 and risk management contracts are considered Level 2.

5. ACQUISITIONS AND DISPOSITIONS

Property disposition - Peace River
On July 8, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.4 million after post-closing adjustments, comprised of $28.4 million in cash and 1.0 million shares of the purchaser. The Company recorded a gain of $0.2 million related to the disposition during the year ended December 31, 2016.

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

Net assets disposed $000s	
Exploration and evaluation assets	7,000
Petroleum and natural gas properties and equipment	37,496
Decommissioning obligations	(15,277)
Total net assets disposed	**29,219**

Asset Exchange Agreement
On September 30, 2016, Petrus closed a property swap transaction disposing of non-core assets in its Foothills area for assets in its Ferrier core area for the swap assets. No gain or loss was realized on the transaction.

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

Net assets disposed $000s	
Exploration and evaluation assets	3,509
Petroleum and natural gas properties and equipment	10,847
Decommissioning obligations	(2,773)
Total net assets disposed	**11,583**

Fair value of net assets acquired $000s	
Petroleum and natural gas properties and equipment	12,388
Decommissioning obligations	(805)
Total net assets acquired	**11,583**

Property dispositions

During the third quarter of 2016, Petrus closed other dispositions of non-core exploration and evaluation assets and petroleum and natural gas properties and equipment for total cash consideration of $0.5 million. No gain or loss was realized on the transaction.

Business combination

On January 20, 2015 Petrus closed an acquisition of petroleum and natural gas assets in the Ferrier area of Alberta, for total cash consideration of $4.4 million, net of adjustments. The transaction was accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed are recorded at fair value. The acquisition was financed by way of the Company's revolving credit facility. Acquisition related costs, which relate to professional fees, are charged to finance expenses in the Statement of Net Loss.

Petrus obtained resource tax pools equal to the total net assets acquired of $4.4 million.

The following table summarizes the net assets acquired pursuant to the acquisition:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,136
Petroleum and natural gas properties and equipment	3,313
Decommissioning obligations	(91)
Total net assets acquired	**4,358**

Property disposition

On February 6, 2015 Petrus closed the disposition of non-core petroleum and natural gas assets in the Pembina area of Alberta for total cash consideration of $7.7 million after post-closing adjustments. The Company recorded a loss of $0.05 million on the divestiture during the year ended December 31, 2015.

Business combination

On February 6, 2015 Petrus closed an acquisition of petroleum and natural gas assets in the Ferrier area of Alberta for total cash consideration of $4.4 million, net of adjustments. The transaction was accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed were recorded at fair value. The acquisition was financed by way of the Company's revolving credit facility. Acquisition related costs, which relate to professional fees, are charged to finance expenses in the Statement of Net Loss.

Petrus obtained resource tax pools equal to the total net assets acquired of $4.4 million. Neither deferred tax nor goodwill was recorded in conjunction with the acquisition.

The following table summarizes the net assets acquired pursuant to the acquisition:

Fair value of net assets acquired $000s	
Exploration and evaluation assets	1,063
Petroleum and natural gas properties and equipment	3,921
Decommissioning obligations	(631)
Total net assets acquired	**4,353**

From the date of their respective acquisitions to December 31, 2015, the above business combinations contributed approximately $0.7 million of revenue and $0.5 million of operating income. If the acquisition had taken place at January 1, 2015, the proforma incremental revenue and operating income (defined as revenue, net of royalties, less operating and transportations costs) of the Company for the year ended December 31, 2015 would have been approximately $0.8 million and $0.6 million, respectively. The proforma information is not necessarily indicative of the results of operations that would have resulted had the acquisitions been effective on the dates indicated, or future results.

Property disposition

On May 7, 2015 Petrus closed the disposition of non-core exploration and evaluation assets in the Ferrier area of Alberta for total cash consideration of $0.1 million. No gain or loss was realized on these transactions.

6. EXPLORATION AND EVALUATION ASSETS

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

$000s	
Balance, December 31, 2014	**94,073**
Additions	941
Property acquisitions	2,199
Corporate acquisitions	(217)
Exploration and evaluation expense	(6,275)
Capitalized G&A	417
Capitalized share-based compensation	130
Transfers to property, plant and equipment	(3,090)
Balance, December 31, 2015	**88,178**
Additions	3
Exploration and evaluation expense	(2,426)
Capitalized G&A	629
Capitalized share-based compensation *(note 11)*	51
Impairment loss on assets held for sale *(note 7)*	(4,000)
Property dispositions *(note 5)*	(10,767)
Transfers to property, plant and equipment *(note 7)*	(6,844)
Balance, December 31, 2016	**64,824**

Exploration and evaluation assets consist of Petrus' undeveloped land and exploration and development projects which are pending the determination of technical feasibility. Additions represent the Company's share of costs incurred on these assets during the period. Exploration and evaluation assets are not subject to depletion. For the year ended December 31, 2016, the Company incurred exploration and evaluation expense in the consolidated Statement of Net Loss and Comprehensive Loss of $2.4 million, which relates to expiring undeveloped, non-core land (2015 – $6.3 million).

During the year ended December 31, 2016, the Company capitalized $0.6 million of general & administrative expenses ("G&A") and $0.05 million of non-cash share-based compensation directly attributable to exploration activities (2015 – $0.4 million and $0.1 million respectively).

The Company determined that indicators of impairment exist on certain exploration & evaluation assets which is undeveloped land in the Foothills CGU. The indicators of impairment included the results of recent crown land sale in the area. Petrus determined that the fair value of its Foothills undeveloped land exceeds the carrying value and therefore no impairment loss was realized. The Company determined fair value by analyzing the geological characteristics of the land, in addition to a review of market land sale information as it relates specifically to Petrus' Foothills undeveloped land.

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, 2014	**661,194**	**(166,474)**	**494,720**
Additions	51,860	—	51,860
Property acquisitions	6,512	—	6,512
Property (dispositions)	(10,781)	3,173	(7,608)
Capitalized G&A	1,251	—	1,251
Capitalized share-based compensation	390	—	390
Transfers from exploration and evaluation assets	3,090	—	3,090
Depletion & depreciation	—	(54,627)	(54,627)
Increase in decommissioning provision	4,798	—	4,798
Impairment loss	—	(67,494)	(67,494)
Balance, December 31, 2015	**718,314**	**(285,422)**	**432,892**
Additions	26,965	—	26,965
Property acquisitions *(note 5)*	12,387	—	12,387
Property dispositions *(note 5)*	(50,319)	—	(50,319)
Capitalized G&A	1,887	—	1,887
Capitalized share-based compensation *(note 11)*	212	—	212
Transfers from exploration and evaluation assets *(note 6)*	6,844	—	6,844
Depletion & depreciation	—	(45,384)	(45,384)
Decrease in decommissioning provision *(note 9)*	(2,281)	—	(2,281)
Impairment loss	—	(21,000)	(21,000)
Balance, December 31, 2016	**714,009**	**(351,806)**	**362,203**

Estimated future development costs of $269.1 million (2015 – $325.3 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, 2016, the Company capitalized $1.9 million of general & administrative expenses ("G&A") and non-cash share-based compensation of $0.2 million directly attributable to development activities (2015 – $1.3 million and $0.4 million respectively).

During the third quarter of 2016, the Company sold its oil and natural gas interests in the Peace River area of Alberta to a private company for total consideration of $30.0 million, subject to customary closing adjustments (see Note 5 - Property Disposition - Peace River). On July 8, 2016 Petrus closed the disposition of its oil and gas interests in the Peace River area of Alberta for total consideration of $29.5 million after post-closing adjustments, comprised of $28.5 million in cash and 1.0 million shares of the purchaser. The Company sold the shares during the fourth quarter of 2016 for $1.07 million. $1.0 million was recorded as cash proceeds for the disposition and the Company recognized a gain of $0.1 million related to the disposition of shares during the year ended December 31, 2016. On June 30, 2016, these assets were recorded at the lesser of fair value less costs of disposal and their carrying amount, resulting in an impairment loss of $25.0 million ($21.0 million recorded to Property, Plant and Equipment and $4.0 million recorded to Exploration & Evaluation Assets). The impairment was recorded as an impairment loss on the consolidated Statements of Net Loss and Comprehensive Loss.

For the year ended December 31, 2016, the Company determined there to be indicators of impairment regarding the Foothills and Central Alberta CGUs, based on the decline in oil and gas forward prices that had affected the economic values of PP&E as well as the fact the carrying amount of the Company's net assets exceed its market capitalization. The Company performed an impairment test for these CGUs, and no impairment charge was recorded as the recoverable amount of each CGU exceeded its carrying value. The recoverable amounts of the Company's CGUs were estimated at fair value less costs of disposal.

For the year ended December 31, 2015, the Company recorded property, plant and equipment impairments of $67.5 million, resulting from a decline in oil and natural gas price forecasts on three of its four CGUs; Central Alberta - $5.0 million; Peace River - $8.8 million; and Foothills - $53.7 million (2014 - $104.8; Central Alberta - $60.3 million; Ferrier - $26.1 million; Peace River - $13.6 million; and Foothills - $4.8 million). The recoverable amounts of the Company's CGUs were estimated at fair value less costs of disposal, based on the net present value of pre-tax cash flows from oil and natural gas reserves, using reserve values estimated by independent reserve evaluators. The recoverable amount for each of the Company's four CGUs was as follows: Central Alberta - $128.7 million; Ferrier - $139.9 million; Peace River - $51.3 million; and Foothills - $74.6 million (2014 - Central Alberta - $155.2 million; Ferrier - $100.2 million; Peace River - $59.7 million; and Foothills - $120.8 million).

In calculating the net present values of cash flows from oil and natural gas reserves, the Company used a pre-tax discount rate of 10% and the following forward commodity price estimates:

December 2015 Sproule Price Deck	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Remainder
Oil (CDN$/bbl) (1)	55.20	69.00	78.43	89.41	91.71	93.08	94.48	95.90	97.34	98.80	100.28	+1.5%/yr
AECO Gas (CDN$/mmBTU)	2.25	2.95	3.42	3.91	4.20	4.28	4.35	4.43	4.51	4.59	4.67	+1.5%/yr

(1)Source: Sproule Canadian price forecasts ($CDN/bbl) for Canadian Light Sweet Crude

As at December 31, 2015, a one percent change in pre-tax discount rate is estimated to change the impairment by approximately $9.4 million; a $1.00/Bbl change in the price of oil is estimated to change the impairment by approximately $4.8 million; and a $0.10/mcf change in the price of natural gas is estimated to change the impairment by approximately $5.5 million.

8. DEBT

At December 31, 2016 Petrus had two debt instruments outstanding. The first is a reserve-based, revolving credit facility with a syndicate of lenders. The total facility is comprised of an operating facility and a syndicated term-out facility (altogether the "Revolving Credit Facility" or "RCF"). The second is a subordinated term loan (the "Term Loan").

(a) Revolving Credit Facility

At December 31, 2016 the Company's RCF was comprised of a $20 million operating facility and a $86 million syndicated term-out facility. The term-out facility has a revolving period that ends July 29, 2017 at which time it will either be renewed or converted to a one-year term facility. The Company has provided collateral by way of a $600 million debenture over all of the present and after acquired property of the Company.

At December 31, 2016, the Company had a $0.3 million letter of credit outstanding against the RCF (December 31, 2015 – $2.4 million) and had drawn $73.8 million against the RCF (December 31, 2015 – $145 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 majority lender consent. A decrease in the borrowing base could result in a reduction to the available credit under the RCF.

(b) Term Loan

At December 31, 2016 the Company had a $42 million (December 31, 2015 – $90 million) Term Loan outstanding which was due October 8, 2017. The Term Loan bears interest is due and payable monthly and accrues at a per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points.

On January 24, 2017 Petrus entered into an agreement to extend the Company's $42 million second lien term loan by two years; now due October 2019. Concurrent with the extension, the Company reduced the amount outstanding by $7 million through working capital and draw down of the RCF. The interest rate on the remaining $35 million balance will remain unchanged at per annum rate of the (three-month) Canadian Dealer offered Rate (CDOR) plus 700 basis points.

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.

PV10 to Net Secured Debt Ratio

Net Secured Debt means all amounts owing under the RCF and any other secured debt of Petrus, minus restricted cash and cash equivalents and "PV10" means the discounted net present value (at a discount rate of 10%) of Petrus' proved reserves, as adjusted for commodity swaps in effect.

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. PV10 to Net Secured Debt Ratios (shown below) must be reported at each borrowing base redetermination date, using the most current reserve report and the Net Secured Debt at the date of the annual borrowing base redetermination which will take place on or before May 31, 2017.

The RCF and the Term Loan carry the following covenants:

a. Working Capital Ratio at the end of each fiscal quarter will not be less than 1.00 to 1.00;
    i. The ratio at December 31, 2016 was 2.20 to 1.00.
b. Proved Asset Coverage Ratio will not be less than 1.25 to 1.00; and
    i. The ratio at December 31, 2016 was 2.31 to 1.00.
c. PDP Asset Coverage Ratio will not be less than 1.00 to 1.00 whereby the asset coverage ratios 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, 2017.
    i. The ratio at December 31, 2016 was 1.56 to 1.00.
d. Debt to EBITDA Ratio will not be greater than 4.00 to 1.00 for the trailing four quarters ending December 31, 2016.
    i. The ratio at December 31, 2016 was 2.83 to 1.00.

At December 31, 2016 the Company is in compliance with all debt covenants.

9. DECOMMISSIONING OBLIGATION

The decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The estimated future cash flows have been discounted using an average risk free rate of 2.24 percent and an inflation rate of 2.00 percent (December 31, 2015 – 2.04 percent and 2.00 percent, respectively). Changes in estimates in 2016 are due to the changes in the risk free rate (change in estimates in 2015 due to the decrease in discount rates and changes in estimated well life). The Company has estimated the net present value of the decommissioning obligations to be $43.2 million as at December 31, 2016 ($64.4 million at December 31, 2015). The undiscounted, uninflated total future liability at December 31, 2016 is $46.0 million ($64.8 million at December 31, 2015). 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, 2014	**58,634**
Property acquisitions	723
Property dispositions	(517)
Liabilities incurred	543
Liabilities settled	(335)
Change in estimates	4,048
Accretion expense	1,261
Balance, December 31, 2015	**64,357**
Property acquisitions *(note 5)*	805
Property dispositions *(note 5)*	(19,854)
Liabilities incurred	1,555
Liabilities settled	(756)
Change in estimates	(3,837)
Accretion expense	973
Balance, December 31, 2016	**43,243**

10. FINANCIAL RISK MANAGEMENT

The Company utilizes commodity contracts as a risk management technique to mitigate exposure to commodity price volatility. The following table summarizes the financial derivative contracts Petrus had outstanding as at December 31, 2016

Natural Gas Contract Period	Contract Type	Daily Volume	Contract Price (CAD$/GJ)
Current			
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.38
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	2,000 GJ	$3.31
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	6,000 GJ	$3.21
Jan. 1, 2017 to Mar. 31, 2017	Costless Collar	5,000 GJ	$2.75 – 3.75
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	2,000 GJ	$2.80
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	4,000 GJ	$2.54
Jan. 1, 2017 to Dec. 31, 2017	Fixed price	2,000 GJ	$2.99
Apr. 1, 2017 to Oct. 31, 2017	Fixed price	5,000 GJ	$2.64
Apr. 1, 2017 to Oct. 31, 2017	Fixed price	7,000 GJ	$2.84
Apr. 1, 2017 to Oct. 31, 2017	Fixed price	2,650 GJ	$2.27
Apr. 1, 2017 to Oct. 31, 2017	Fixed price	2,000 GJ	$2.65
Apr. 1, 2017 to Oct. 31, 2017	Costless Collar	2,000 GJ	$2.50 – 2.75
Nov. 1, 2017 to Dec. 31, 2017	Fixed price	5,000 GJ	$3.02
Nov. 1, 2017 to Dec. 31, 2017	Fixed price	1,500 GJ	$2.69
Nov. 1, 2017 to Dec. 31, 2017	Fixed price	3,000 GJ	$2.91
Nov. 1, 2017 to Dec. 31, 2017	Costless Collar	2,000 GJ	$2.80 – 3.35
Nov. 1, 2017 to Dec. 31, 2017	Fixed price	4,000 GJ	$3.17
Non-Current			
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	5,000 GJ	$3.02
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	1,500 GJ	$2.69
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	3,000 GJ	$2.91
Jan. 1, 2018 to Mar. 31, 2018	Costless Collar	2,000 GJ	$2.80 – 3.35
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	4,000 GJ	$3.17
Apr. 1, 2018 to Oct. 31, 2018	Fixed price	4,000 GJ	$2.45
Apr. 1, 2018 to Oct. 31, 2018	Fixed price	3,000 GJ	$2.41
Apr. 1, 2018 to Oct. 31, 2018	Fixed price	3,000 GJ	$2.43

Crude Oil Contract Period	Contract Type	Daily Volume	Contract Price (WTI CAD$/Bbl)
Current			
Jan. 1, 2017 to Mar. 31, 2017	Costless Collar	500 Bbl	$70.00-78.00
Jan. 1, 2017 to Mar. 31, 2017	Costless Collar	100 Bbl	$65.00-71.00
Jan. 1, 2017 to Mar. 31, 2017	Fixed price	300 Bbl	$65.45
Jan. 1, 2017 to Jun. 30, 2017	Costless Collar	500 Bbl	$70.00-78.40
Apr. 1, 2017 to Jun. 30, 2017	Costless Collar	400 Bbl	$65.00-72.70
Apr. 1, 2017 to Jun 30, 2017	Fixed price	300 Bbl	$59.25
Apr. 1, 2017 to Jun. 30, 2017	Fixed price	100 Bbl	$67.55
Jul. 1, 2017 to Sep. 30, 2017	Fixed price	600 Bbl	$59.80
Jul. 1, 2017 to Sep. 30, 2017	Costless Collar	500 Bbl	$65.00-74.20
Oct. 1, 2017 to Dec. 31, 2017	Costless Collar	400 Bbl	$65.00-75.85
Oct. 1, 2017 to Dec. 31, 2017	Costless collar	100 Bbl	$60.00-73.20
Oct. 1, 2017 to Dec. 31, 2017	Fixed price	100 Bbl	$72.55
Oct. 1, 2017 to Dec. 31, 2017	Costless collar	300 Bbl	$55.00-64.02
Non-Current			
Jan. 1, 2018 to Mar. 31, 2018	Costless collar	300 Bbl	$55.00-64.02
Jan. 1, 2018 to Mar. 31, 2018	Costless collar	300 Bbl	$60.00-73.60
Jan. 1, 2018 to Mar. 31, 2018	Fixed price	100 Bbl	$71.85
Apr. 1, 2018 to Jun. 30, 2018	Fixed price	400 Bbl	$71.15
Jul. 1, 2018 to Sep. 30, 2018	Fixed price	400 Bbl	$70.85

Risk Management Asset and Liability:

$000s At December 31, 2016	Asset	Liability
Current commodity derivatives	22	5,696
Non-current commodity derivatives	—	1,924
	22	**7,620**

$000s At December 31, 2015	Asset	Liability
Current commodity derivatives	13,978	45
Non-current commodity derivatives	—	—
	13,978	**45**

Earnings Impact of Realized and Unrealized Gains (Losses) on Financial Derivatives:

$000s	Year ended Dec. 31, 2016	Year ended Dec. 31, 2015
Realized gain on financial derivatives	15,002	16,563
Unrealized loss on financial derivatives	(21,531)	(479)
Net gain (loss) on financial derivatives	**(6,529)**	**16,084**

Subsequent to December 31, 2016, the Company entered into the following financial derivative contracts:

Natural Gas Contract Period	Contract Type	Daily Volume	Contract Price (WTI CAD$/Bbl)
Non-Current			
Apr. 1, 2018 to Oct. 31, 2018	Fixed price	3,000 GJ	$2.335
Nov. 1, 2018 to Mar. 31, 2019	Fixed price	5,000 GJ	$2.655

Crude Oil Contract Period	Contract Type	Daily Volume	Contract Price (WTI CAD$/Bbl)
Current			
Jul. 1, 2017 to Sep. 30, 2017	Fixed price	50 Bbl	$72.92
Oct. 1, 2017 to Dec. 31, 2017	Fixed price	150 Bbl	$73.00
Non-Current			
Jan. 1, 2018 to Dec. 31, 2018	Fixed price	300 Bbl	70.85

11. SHARE CAPITAL

Authorized

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

Issued and Outstanding

Common shares ($000s *except number of shares*)	Number of Shares	Amount
Balance, December 31, 2014 and 2015	**35,148,150**	**346,106**
Common shares issued under equity financing (a)	4,054,250	30,000
Common shares issued under the arrangement agreement (b)	6,146,792	45,487
Share issue costs	—	(1,922)
Balance, December 31, 2016	**45,349,192**	**419,671**

Share Issuances

(a) On February 2, 2016 the Company issued 4,054,250 common shares at a price of $7.40 per share.

(b) On February 2, 2016 the Company issued 6,146,792 common shares at a price of $7.40 in conjunction with the Arrangement Agreement with PhosCan Chemical Corp. *(note 1)*.

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SHARE-BASED COMPENSATION

Performance Warrants

The Company has issued performance warrants to employees, consultants and directors of the Company ("Performance Warrants"). Performance Warrants were granted and vest based on three criteria, time (one third vest per year), market (one third vest as certain share price hurdles are achieved) and employment or service. The Performance Warrants expire five years from the date of issuance. Upon exercise of the Performance Warrants the Company may settle the obligation by issuing common shares of the Company. The shares to be offered consist of common shares of the Company's authorized but unissued common shares. The aggregate number of shares issuable upon the exercise of all Performance Warrants granted shall not exceed 20% of the 8.0 million issued and outstanding common shares as at April 30, 2012.

At December 31, 2016, 429,667 (December 31, 2015 – 1,568,568) Performance Warrants were issued and outstanding summarized in the table below.

	Number of warrants outstanding	Weighted Average Exercise Price ($)
Balance, December 31, 2015	**1,568,568**	**$8.07**
Forfeited or expired	(1,138,901)	$8.02
Balance, December 31, 2016	**429,667**	**$8.14**
Exercisable, December 31, 2016	**252,409**	**$8.08**

The following table summarizes information about the Performance Warrants granted since inception:

Range of Exercise Price	Warrants Outstanding			Warrants Exercisable		
	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining life (years)
$8.00 - $9.00	429,667	$8.14	0.60	252,409	$8.08	0.54
Total	**429,667**	**$8.14**	**0.60**	**252,409**	**$8.08**	**0.54**

No Performance Warrants were issued in the years ended December 31, 2016 or 2015.

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 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.

Petrus amended its stock option plan following the Arrangement Agreement (see Note 1). Petrus has issued options under the old option plan as well as the new option plan; the terms are consistent under both plans.

At December 31, 2016, 1,976,580 (December 31, 2015 – 1,453,750) total stock options were outstanding. The summary of stock option activity is presented below:

	Number of stock options	Weighted average exercise price
Balance, December 31, 2015	**1,453,750**	**$9.28**
Granted	791,580	$1.98
Forfeited or expired	(268,750)	$7.00
Balance, December 31, 2016	**1,976,580**	**$6.56**
Exercisable, December 31, 2016	**917,917**	**$8.74**

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)
$1.98 - $2.00	791,580	$1.98	4.88	—	$1.98	4.88
$7.00 - $8.00	650,000	$7.00	0.44	650,000	$7.00	0.44
$8.01 - $11.00	147,500	$9.61	2.08	67,084	$9.77	2.08
$11.01 - $16.00	387,500	$14.01	2.76	200,833	$14.02	2.71
	1,976,580	**$6.56**	**0.85**	**917,917**	**$8.74**	**1.05**

On November 16, 2016 the Company granted options which vest equally over three (3) years, and upon vesting, expire 30 business days thereafter. The weighted average fair value of each option granted in 2016 of $1.98 (2015 – $4.96) was estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions:

	2016	2015
Risk free interest rate	0.67% - 0.73%	1.20% - 1.40%
Expected life (years)	1.08 - 3.08	5
Estimated volatility of underlying common shares (%)	55%	50%
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.

The following table summarizes the Company's share-based compensation costs for the years ended December 31, 2016 and 2015:

$000s	2016	2015
Expensed in net loss	527	655
Capitalized to exploration and evaluation assets	51	130
Capitalized to property, plant and equipment	212	390
Total share-based compensation	**789**	**1,175**

12. EARNINGS PER SHARE

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

		Year ended Dec. 31, 2016	Year ended Dec. 31, 2015
Net loss for the year ($000s)		**(66,988)**	**(69,031)**
Weighted average number of common shares – basic (000s)		44,429	35,148
Weighted average number of common shares – diluted (000s)		44,429	35,148
Net loss per common share – basic	**$**	**(1.51) $**	**(1.96)**
Net loss per common share – diluted	**$**	**(1.51) $**	**(1.96)**

In computing diluted earnings per share for the year ended December 31, 2016, 429,667 (December 31, 2015 – 1,568,568) warrants and 1,976,580 (December 31, 2015 – 1,552,084) outstanding stock options were considered, however no instruments (performance warrants or stock options) were added to the calculation as their impact is anti-dilutive.

13. OPERATING EXPENSES

The Company's gross operating expenses for the year ended December 31, 2016 were $22.3 million (December 31, 2015 – $31.2 million), which includes $5.2 million of processing, gathering and compression charges (December 31, 2015 – $8.5 million).

The Company generated processing income recoveries of $2.7 million for the year ended December 31, 2016 (December 31, 2015 – $2.7 million), which reduced the Company's gross operating expenses to $19.5 million for the year ended December 31, 2016 (December 31, 2015 – $28.5 million).

14. GENERAL AND ADMINISTRATIVE EXPENSES

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

$000s	Year ended Dec. 31, 2016	Year ended Dec. 31, 2015
Personnel, consultants and directors	6,593	4,554
Regulatory expenses	1,017	1,697
Office costs	2,130	2,533
Subscriptions & licenses	137	161
Public company expenses	248	10
Transaction costs	39	213
Capitalized general and administrative	(2,458)	(1,668)
General and administrative expense	**7,706**	**7,500**

15. FINANCIAL INSTRUMENTS

Risks associated with financial instruments

Credit risk

The Company may be exposed to certain losses in the event that counterparties to financial instruments fail to meet their obligations in accordance with agreed terms. The Company mitigates this risk by entering into transactions with highly rated major financial institutions and by routinely assessing the financial strength of its customers.

At December 31, 2016, financial assets on the balance sheet are comprised of cash, deposits, risk management assets and accounts receivable. The maximum credit risk associated with these financial instruments is the total carrying value.

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 $11.5 million of accounts receivable outstanding at December 31, 2016 (December 31, 2015 – $17.8 million), $10.5 million is owed from 10 parties (December 31, 2015 – $15.7 million from 21 parties), and the balance was received subsequent to year end. The Company considers accounts receivable outstanding past 120 days to be 'past due'. At December 31, 2016, Petrus does not have an allowance for doubtful accounts ($0.2 million at December 31, 2015). As at December 31, 2016 and 2015, 98% of Petrus' accounts receivable were aged less than 120 days and 2% of Petrus' accounts receivable were aged greater than 120 days. The Company does not anticipate any significant collection issues.

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

Liquidity risk

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 accounts payable, long term debt and risk management liabilities. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future cash flows.

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

At December 31, 2016, the Company had a $106 million RCF (refer to note 8), of which $31.9 million was undrawn at year end (December 31, 2015 – the Company had a $160 million credit facility of which $12.6 million was undrawn at year end). The RCF was reduced during the year due to a reduction in commodity prices which led to a decrease in the lending value attributed to Petrus' oil and gas assets. In addition, the disposition of the Company's oil and natural gas assets in the Peace River area contributed to the reduction in RCF. During the year Petrus repaid $119 million in debt using proceeds from the equity issuance in the first quarter of 2016, as well as proceeds from the Peace River asset disposition in the third quarter of 2016.

While the Company is exposed to the risk of reductions to the borrowing base of the RCF, Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through cash flows from operating activities and available credit capacity from its RCF. Further, Petrus completed its semi-annual review of its revolving credit facility on October 31, 2016, whereby the syndicate of lenders unanimously agreed to maintain the facility at $106 million. The next scheduled borrowing base redetermination date for the RCF is on or before May 31, 2017.

At December 31, 2016 the Term Loan was classified as current as management had not finalized an extension prior to this date. On January 24, 2017 Petrus finalized an agreement with its Term Loan provider to extend the Company's $42 million second lien term loan by two years; now due October 2019. Concurrent with the extension, the Company reduced the amount outstanding by $7 million through working capital and and available credit from its RCF. The interest rate on the remaining $35 million balance will remain unchanged at the Canadian Dealer Offered Rate (CDOR) plus 700 basis points (which is currently a total interest rate of 7.9%).

The following are the contractual maturities of financial liabilities as at December 31, 2016:

$000s	Total	< 1 year	1-5 years
Accounts payable	22,066	22,066	—
Risk management liability	7,620	5,696	1,924
Bank debt(1)	115,767	42,000	73,767
Total	**145,453**	**69,762**	**75,691**

(1) On January 24, 2017 the maturity and repayment date was extended to October 8, 2019 for the Term Loan.

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 and accounts receivable are not exposed to significant interest rate risk. The RCF and Term Loan are exposed to interest rate cash flow risk as the instruments are priced on a floating interest rate subject to fluctuations in market interest rates. The remainder of Petrus' financial assets and liabilities are not exposed to interest rate risk. A 1% increase in the Canadian prime interest rate during the year ended December 31, 2016 would have increased net loss by approximately $1.8 million, which relates to interest expense on the average outstanding RCF and Term Loan during the year, assuming that all other variables remain constant (December 31, 2015 – $2.1 million). A 1% decreased 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.

Petrus manages the risks associated with changes in commodity prices by entering into a variety of financial derivative contracts (see note 10 - Financial Risk Management). 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.

For the year ended December 31, 2016, it is estimated that a $0.25/GJ change in the price of natural gas would have changed net loss by $2.6 million (December 31, 2015 – $3.6 million). For the year ended December 31, 2016, it is estimated that a $5.00/CDN WTI/bbl change in the price of oil would have changed net loss by $1.5 million (December 31, 2015 – $3.2 million). An opposite change in commodity prices would result in an opposite impact on net loss.

16. CAPITAL MANAGEMENT

The Company's general capital management policy is to maintain a sufficient capital base in order to manage its business to enable the Company to increase the value of its assets and therefore its underlying share value. The Company's objectives when managing capital are (i) to manage financial flexibility in order to preserve the Company's ability to meet financial obligations; (ii) maintain a capital structure that allows Petrus the ability to finance its growth using internally generated cashflow and (iii) to maintain a flexible capital structure which optimizes the cost of capital at an acceptable risk level and provides an optimal return to equity holders.

In the management of capital, Petrus includes share capital and total net debt, which is made up of debt and working capital (current assets less current liabilities). Petrus 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 (refer to note 8 - Debt for restrictions).

17. FINANCE EXPENSES

The components of finance expenses are as follows:

$000s	2016	2015
Cash:		
Interest	10,587	13,366
Foreign exchange	50	(567)
Total cash finance expenses	**10,637**	**12,799**
Non-cash:		
Deferred financing costs	—	1,216
Accretion on decommissioning obligations *(note 9)*	973	1,261
Total non-cash finance expenses	973	2,477
Total finance expenses	**11,610**	**15,276**

18. DEFERRED INCOME TAXES

$000s	2016	2015
Income (loss) before taxes	(66,988)	(86,794)
Combined federal and provincial tax rate	27.0%	26.0%
Computed “expected” tax expense (recovery)	(18,086)	(22,566)
Increase/(decrease) in taxes resulting from:		
Permanent items	5	177
Share based payments	142	—
Share issuance costs	(473)	—
Tax impact of flow-through shares	—	—
Impact of rate change	—	633
True up and other	373	918
Unrecognized deferred income tax asset	18,039	3,075
Deferred tax expense (recovery)	—	**(17,763)**
Effective tax rate	—	**20.6%**

The components of the Company’s deferred tax position at December 31, 2016 and 2015 are as follows:

$000s	2016	2015
Net book value of assets in excess of tax pools	(24,439)	(32,774)
Asset retirement obligations	11,676	17,376
Share issuance costs	911	967
Non capital loss carry-forwards	9,801	18,193
Unrealized hedging gain (loss)	2,051	(3,762)
Deferred tax liability	—	—

As at December 31, 2016, Petrus did not recognize income tax assets from non-capital losses of approximately $78.2 million (December 31, 2015 – $11.5 million).

The Company had non-capital losses of approximately $114.5 million (2015 – $81.8 million) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2026 and onwards.

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	2016	2015
Source (use) in non-cash working capital:		
Deposits and prepaid expenses	(25)	(67)
Accounts receivable	6,227	5,582
Accounts payable and accrued liabilities	10,227	(57,992)
	16,429	**(52,477)**
Operating activities	14,041	(28,779)
Financing activities	323	458
Investing activities	2,065	(24,156)

20. RELATED PARTY TRANSACTIONS

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

$000s	2016	2015
Salaries, consulting fees, benefits and director fees, gross	1,728	931
Termination payments and benefits	663	—
Share based compensation, gross	15	761
	2,406	**1,692**

21. COMMITMENTS

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

$000s	Total	< 1 year	1-5 years	> 5 years
Corporate office lease	2,240	749	1,491	—
Firm service transportation	7,505	815	4,074	2,617
Total commitments	**9,745**	**1,564**	**5,565**	**2,617**

22. SUBSEQUENT EVENTS

Property Acquisition

On February 28, 2017 Petrus closed an acquisition of certain oil and natural gas interests in the Ferrier area of Alberta for cash consideration of $8.9 million including closing adjustments.

Private Placement

On February 28, 2017 the Company closed a non-brokered private placement of 4,078,708 common shares of the Company ("Common Shares") at a purchase price of $2.53 per Common Share, for aggregate gross proceeds of $10.3 million (the "Private Placement").

CORPORATE INFORMATION

OFFICERS

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President and
Chief Executive Officer

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

Marcus Schlegel, P. Eng.
Vice President, Engineering

Brett Booth, BA
Vice President, Land

Ross Keilly, BSc, MSc
Vice President, Exploration

DIRECTORS

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Chairman
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Neil Korchinski
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Donald Cormack
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AUDITOR
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Chartered Professional Accountants
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