2013 Annual Report

HIGHLIGHTS

Petrus Resources Ltd. (“Petrus” or the “Company”) is pleased to report operating and financial results for the fourth quarter and the fiscal year of 2013. Petrus began 2013, its second full year of operations, with production of 2,853 boe per day (42% oil and liquids) and exited the year at a record 4,052 boe per day (46% oil and liquids), a 42% increase. The Company set new records for production, cash flow and reserves per share in 2013. Other highlights include:

- Production per share up 21% in 2013. Average annual production was 3,206 boe per day in 2013, up from 1,880 boe per day in 2012. Fourth quarter production averaged 3,658 boe per day, up from 2,735 boe per day in the same period of 2012, an increase of 34% per share. New Montney and Cardium oil production generated a 44% increase in oil and natural gas liquids production from the first quarter to the fourth quarter of 2013, driving strong growth in cash flow per share.

- Cash flow per share up 77% in 2013. Petrus generated $31.1 million in cash flow from operations during the year, a two-and-a-half-fold increase over the $12.5 million generated in 2012. Cash flow from operations was $9.2 million in the fourth quarter, up from $6.3 million in the same period last year, an increase of 39% on a per share basis.

- Operating netback up 35% in 2013, rising from $21.29 per boe in 2012 to $28.74 per boe in 2013. The Company’s operating netback in the fourth quarter was $31.04.

- Reserves per share up 21% in 2013. Proved plus probable reserves increased from 12.3 mmboe in 2012 to 14.9 mmboe in 2013. The Company replaced 3.2 times annual production at an all-in annual Finding, Development and Acquisition (“FD&A”) cost of $21.57 per boe including future development capital (“FDC”) for the proved plus probable category.

- Petrus ended 2013 with $228.1 million of reserve value on a proved plus probable basis, discounted at 10%, 1.6 times the prior year total. On a per share basis, adjusted for debt, the proved plus probable reserve value was up 35%.

- Over the twelve month period ended December 31, 2013, Petrus invested $58.9 million in exploration and acquisition activity, up from $52.2 million in 2012.

- Petrus had 86.4 million common shares outstanding at December 31, 2013 and access to a $60.0 million credit facility. The Company ended the year with net debt of $22.3 million, or 0.6x annualized fourth quarter cash flow. The debt-adjusted growth per share metrics year-over-year are 26% for exit production, 55% for cash flow and 7% for proved plus probable reserves.

- At year end Petrus had 133,339 net acres of undeveloped land, with a large inventory of oil and gas drilling locations in each of its core operating areas.

- Subsequent to December 31, 2013 Petrus announced the acquisition of oil and natural gas assets in the foothills of Alberta; included in this acquisition were 875 boe per day of production and 36,307 net acres of undeveloped land. The acquisition was made for total cash consideration of approximately $19.1 million (before post-closing adjustments) and closed February 28, 2014. Concurrently the Company’s borrowing base increased to $90 million, including a $10 million development line.

- The Petrus Board of Directors approved a base capital budget of $74 million for 2014, excluding acquisitions. The capital budget provides for the drilling of 36 gross (24 net) wells, with approximately $45 million directed at foothills development and $29 million directed toward the Peace River area. Concurrent with closing of the acquisition of foothills assets the capital budget increased to $100 million. The capital budget will be funded through cash flow and available credit facilities.

SELECTED FINANCIAL INFORMATION

(000s) except per boe amounts	Twelve months ended Dec. 31, 2013	Twelve months ended Dec. 31, 2012	Three months ended Dec. 31, 2013	Three months ended Sept. 30, 2013	Three months ended June 30, 2013	Three months ended Mar. 31, 2013
OPERATIONS						
Average Production						
Natural gas (mcf/d)	10,314	7,490	10,848	10,405	9,681	10,315
Oil (bbl/d)	1,417	585	1,778	1,373	1,300	1,212
NGLs (bbl/d)	70	47	72	54	76	76
Total (boe/d)	**3,206**	**1,880**	**3,658**	**3,162**	**2,990**	**3,007**
Total (boe)	**1,170,141**	**686,200**	**336,539**	**290,877**	**272,090**	**270,638**
Natural gas sales weighting	***54%***	***66%***	***49%***	***55%***	***54%***	***57%***
Exit production (boe/d)	***4,052***	***2,853***	***4,052***	***3,235***	***3,065***	***3,071***
Exit natural gas sales weighting	***54%***	***58%***	***54%***	***53%***	***53%***	***53%***
Realized Sales Prices						
Natural gas ($/mcf)	3.30	2.61	3.78	2.54	3.60	3.29
Oil ($/bbl)	83.95	79.07	77.83	93.93	88.13	77.02
NGLs ($/bbl)	61.87	61.16	65.17	67.20	45.37	71.55
Total ($/boe)	49.08	36.53	50.33	50.31	51.14	44.15
Hedging gain (loss) ($/boe)	(1.12)	0.82	(1.21)	(1.46)	(0.55)	(1.21)
Operating Netback ($/boe)						
Effective price	47.96	37.35	49.12	48.85	50.59	42.94
Royalty income (1)	0.53	0.54	0.46	0.56	0.57	0.55
Royalty expense (1)	(7.66)	(5.10)	(7.05)	(8.02)	(7.39)	(8.31)
Operating expense	(10.26)	(10.32)	(9.88)	(8.46)	(10.12)	(11.38)
Transportation expense	(1.83)	(1.18)	(1.61)	(2.19)	(1.71)	(1.82)
Operating netback (3) ($/boe)	**28.74**	**21.29**	**31.04**	**30.74**	**31.94**	**21.98**
G & A expense	(1.59)	(2.74)	(1.73)	(1.96)	(1.57)	(1.02)
Net interest expense (2)	(0.59)	(0.38)	(0.75)	(0.74)	(0.79)	(0.02)
Corporate netback (3) ($/boe)	**26.56**	**18.18**	**28.56**	**28.04**	**29.58**	**20.94**
FINANCIAL ($000s except per share)						
Oil and natural gas revenue (1)	58,055	25,511	17,094	14,741	14,093	12,128
Cash flow from operations (3)	31,091	12,513	9,220	8,157	8,048	5,666
Cash flow from operations per share (3)	0.36	0.20	0.11	0.09	0.09	0.06
Net income (loss)	8,141	431	2,086	2,171	4,010	47
Net income (loss) per share	0.09	0.01	0.02	0.03	0.05	0.01
Capital expenditures	58,851	52,159	9,736	14,166	15,416	19,533
Net acquisitions (dispositions)	(1,701)	59,630	—	—	(1,701)	—
Common shares outstanding	86,377	86,276	86,377	86,377	86,362	86,276
Weighted average shares	86,343	61,377	86,377	86,369	86,349	86,276
As at quarter end ($000s)						
Working capital (deficit)	(22,288)	2,793	(22,288)	(21,558)	(15,756)	(10,551)
Bank debt outstanding	23,380	—	23,380	17,966	20,968	11,304
Bank debt available	36,620	40,000	36,620	42,034	39,032	28,696
Shareholder's equity	156,002	145,782	156,002	153,857	151,304	146,432
Total assets	211,952	181,976	211,952	201,208	199,508	184,139

(1) The Company re-classified gross overriding royalty expense from oil and natural gas revenue to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.
(2) Interest expense is presented net of interest income.
(3) Non-GAAP measures defined on page 7 of the MD&A for the period ended December 31, 2013.

OPERATIONS UPDATE

Foothills

Drilling success continues to add new oil weighted production in the foothills. Average production in the fourth quarter of 2013 from the Cordel area increased approximately 538 boe per day from the third quarter of 2013. Three successful light oil wells were drilled in the fourth quarter of 2013. The last well, in which Petrus has a 25% working interest, has delivered the highest initial production rate from an oil well at Cordel to date, with gross production averaging 1,420 boe per day (90% oil) over a 30 day period in January and February. The sales increase from the prior quarter is also due to the completion of permanent production facilities in the fourth quarter. These facilities enabled the multi-well pad drilled earlier in 2013 to produce at near full rates for the fourth quarter.

The foothills asset acquisition added 875 boe per day (94% natural gas). The base purchase price of $22.9 million was reduced to net cash consideration of $19.1 million, as $2.6 million was received due to exercise of a third party ROFR on a minor facility working interest in addition to purchase price adjustments related to the interim period. The acquisition was funded using available credit facilities and closed February 28, 2014. The acquisition provides Petrus with drilling upside at current commodity prices and increased working interest on near term oil drilling opportunities at Brown Creek where Petrus plans to resume drilling in the summer of 2014. The Company has identified additional drilling locations targeting various reservoirs in other strike areas, as well as reactivation opportunities.

Peace River

During the fourth quarter Petrus finished completions and tie-in of the six wells drilled in the summer of 2013. Two of these wells are water disposal wells. New Montney oil wells produced a combined total of approximately 100 boe per day (90% light oil) once brought onto production in December.

During the fourth quarter Petrus completed a battery with water disposal at Tangent North and the system is now operational. A second disposal system at Tangent South was completed at the end of the first quarter of 2014. Both batteries are expected to significantly decrease operating costs, increase runtime and allow for waterflood, which the Company believes will ultimately increase Montney oil recoveries. Petrus has made an application to the provincial regulator for a pilot waterflood at Tangent North which, if approved, is expected to commence in the second half of 2014.

Petrus resumed drilling in Tangent in January with a seven well program targeting oil in the Montney formation. Two of the wells had test rates over a 32 hour period in excess of 200 bbl per day of oil with lower water cuts than expected. These wells will be brought on production over the summer of 2014 dependent on weather and surface conditions.

ANNUAL GENERAL MEETING

The Company's Annual General Meeting will be held at the Jamieson Place Conference Centre, 3rd floor, 308-4th Ave SW Calgary, Alberta, on Tuesday June 3, 2014 at 9:00 a.m. (Calgary time). The Information Circular and Annual Report for 2013 will be available on the Company's website, www.petrusresources.com.

PRESIDENT'S MESSAGE

Petrus continued on a very exciting growth profile in 2013 deploying $58.9 million on various projects during the year almost exclusively targeting light oil additions.

Drilling continued on the prolific Cordel/Stolberg structure in the Canadian foothills resulting in several outstanding oil wells. Petrus' average working interest has increased in the latest wells to 25 – 30 percent from 9 – 21 percent in the earlier wells in the program. With additional wells, the structural interpretation is better refined and additional opportunities are better understood. Together with other owners, Petrus is looking at the viability of secondary recovery techniques to optimize recovery factors. During 2014 Petrus expects to participate in several additional Cordel wells and expects to resume drilling on a similar structure targeting oil at Brown Creek.

Petrus has also advanced development of our Tangent Montney projects with the construction of two multi-well batteries and water disposal systems. These investments are expected to dramatically reduce operating expenses associated with trucking water from single well batteries. Longer term, these facility assets will be utilized to implement waterfloods in the Montney reservoirs improving ultimate recoveries. Petrus has drilled both unstimulated horizontal wells and vertical wells to determine the optimal depletion strategy for development of its extensive Montney acreage. Recent commissioning of these facilities together with additional drilling will provide us with valuable design data for long term exploitation of these resources.

Late in the year oil and gas sales reached a record 4,000 boe per day and, following an 875 boe per day acquisition in the first quarter, recent sales rates have been approximately 5,000 boe per day. Importantly, our oil and liquids sales have increased from less than 100 bbls per day in mid-2012 to over 2,000 bbls per day currently. These are very important growth milestones achieved in a relatively short period of time.

Commodity prices continued to show strength through 2013. Increasing build-out of rail capacity in Western Canada together with incremental pipeline takeaway capacity from Cushing Oklahoma has reduced overall oil price differentials. Pipeline takeaway capacity from Alberta remains a very important issue for all Canadians and progress on these critical national infrastructure projects must be made soon.
Gas prices were relatively weak during the summer but an early, cold, and long winter across most of North America has resulted in record withdrawals from storage. These withdrawals together with a 10% slide in the Canadian dollar, resulted in realized gas prices improving dramatically during the fourth quarter and through the first quarter of 2014. In spite of these recent higher gas prices, gas directed drilling is still subdued and the industry will face challenges to refill storage prior to next winter to levels achieved in recent years. Petrus expects gas prices to remain well supported through 2014.

The slow global economic recovery is beginning to generate life in equity markets for Canadian juniors. Overall, valuations are improving. Acquisition and divestiture activity is recovering along with associated financings. Petrus has been active evaluating a variety of potential transactions. With a very strong base of production and cash flow, a lightly levered balance sheet, and strong shareholder support, Petrus is in an enviable position. 2014 should prove to be another exciting growth year on many fronts.

Kevin Adair
President, CEO and Director

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, 2013. The report is dated April 11, 2014. This MD&A should be read in conjunction with the December 31, 2013 audited financial statements. Readers are directed to the advisories at the end of this report regarding forward-looking statements, BOE presentation and non-IFRS measures.

FINANCIAL AND OPERATIONAL RESULTS OF OIL AND NATURAL GAS ACTIVITIES

	Twelve months ended Dec. 31, 2013	Twelve months ended Dec. 31, 2012	Three months ended Dec. 31, 2013	Three months ended Sept. 30, 2013	Three months ended June 30, 2013	Three months ended Mar. 31, 2013
Quarterly average production						
Natural gas (mcf/d)	10,314	7,490	10,848	10,405	9,681	10,315
Oil (bbl/d)	1,417	585	1,778	1,373	1,300	1,212
NGLs (bbl/d)	70	47	72	54	76	76
Total (boe/d)	**3,206**	**1,880**	**3,658**	**3,162**	**2,990**	**3,007**
Total (boe)	1,170,141	688,205	336,539	290,877	272,090	270,638
Exit production (boe/d)	4,052	2,853	4,052	3,235	3,065	3,071
Exit gas weighting	54%	58%	54%	53%	53%	53%
Revenue (000s)						
Natural Gas	12,438	7,157	3,775	2,431	3,174	3,058
Oil	43,425	16,930	12,734	11,866	10,426	8,399
NGLs	1,572	1,052	430	336	315	491
Commodity revenue	57,435	25,139	16,939	14,634	13,915	11,948
Royalty revenue (1)	620	373	155	107	179	180
Oil and natural gas revenue (1)	58,055	25,511	17,094	14,741	14,094	12,128
Average realized prices						
Natural gas ($/mcf)	3.30	2.61	3.78	2.54	3.60	3.29
Oil ($/bbl)	83.95	79.07	77.83	93.93	88.13	77.02
NGLs ($/bbl)	61.87	61.16	65.17	67.20	45.37	71.55
Total ($/boe)	49.08	36.53	50.33	50.31	51.14	44.15
Hedging gain (loss)	(1.12)	0.82	(1.21)	(1.46)	(0.55)	(1.21)
Total realized ($/boe)	47.96	37.35	49.12	48.85	50.59	42.94
Average benchmark prices	**Twelve months ended Dec. 31, 2013**	**Twelve months ended Dec. 31, 2012**	**Three months ended Dec. 31, 2013**	**Three months ended Sept. 30, 2013**	**Three months ended June 30, 2013**	**Three months ended Mar. 31, 2013**
Natural gas						
AECO (C$/mcf)	3.19	2.39	3.53	2.43	3.53	3.26
Crude Oil						
Edm Lt. (C$/ bbl)	93.30	87.41	86.70	105.05	92.90	88.54
Foreign Exchange						
US$/C$	0.97	1.00	0.94	0.96	0.98	1.00

(1) *The Company re-classified gross overriding royalty expense from oil and natural gas revenue to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.*

OIL AND NATURAL GAS REVENUE

Average production for the fourth quarter of 2013 was 3,658 boe per day (49% natural gas), compared to 2,735 boe per day (56% natural gas) for the fourth quarter of the prior year. Total commodity revenue increased from $25.1 million in 2012 to $57.4 million in the year ended December 31, 2013. The increase is due to the Company's on-going drilling success and improved commodity prices.

Natural gas

During the three months ended December 31, 2013, the benchmark natural gas price in Canada (set at the AECO hub) increased by 10% from the prior year (average price of $3.53 per mcf in the fourth quarter compared to $3.21 per mcf in the prior year). The AECO price increased 33% from the average annual price of $2.39 per mcf in 2012 to $3.19 per mcf in 2013. Demand and pricing for natural gas peaked in February 2013 and normalized later in April. The average price of $3.19 for 2013 approximates the five year average. Near the end of the year, stockpiles were depleted faster than expected and natural gas prices climbed 19% from the third quarter to the fourth quarter of 2013 and 7% in the final month of the year. Cold fronts began their sweep across the United States in December and continued into 2014.

The Company's average realized gas price during the fourth quarter of 2013 was $3.78 per mcf compared to $3.49 per mcf in the prior year, which represents an 8% increase. Natural gas revenue for the fourth quarter of 2013 was $3.8 million and production of 998,016 mcf accounted for approximately 50% of fourth quarter production volume and 22% of commodity revenue (compared to revenue of $2.9 million and production of 839,776 mcf for 56% of production volume and 26% of commodity revenue in the prior year).

The Company's average realized gas price for the year ended December 31, 2013 was $3.30 per mcf compared to $2.61 per mcf in the prior year, which represents a 26% increase. Natural gas revenue for the year ended December 31, 2013 was $12.4 million and production of 3,764,610 mcf accounted for approximately 54% of 2013 production volume and 22% of commodity revenue (compared to revenue of $7.2 million and production of 2,733,850 mcf for 66% of production volume and 29% of commodity revenue in the prior year).

Crude oil and condensate

Edmonton Light Sweet ("Edmonton") crude oil prices increased 11% from the fourth quarter of 2012 to the fourth quarter of 2013 ($97.43 per bbl for the fourth quarter of 2013 compared to an average price of $87.96 per bbl for the prior period). In July WTI prices began to rally and held a range above $100 per bbl through the summer. This increase in prices was driven in part by new pipeline infrastructure which connected the U.S. Gulf Coast to Cushing. The infrastructure expansion enabled a significant draw from storage. In addition, prices were driven higher near the end of the fourth quarter by conflict in Syria and an oil worker strike in Libya. Subsequent to the end of the fourth quarter, oil prices receded as geopolitical risk has decreased and turnaround season began.

The average realized price of Petrus' crude oil and condensate was $93.93 per bbl for the fourth quarter of 2013 compared to $80.55 per bbl for the same period in the prior year. For the year ended December 31, 2013 the Company's average realized price for crude oil and condensate increased 6 percent from 2012, primarily as a result of an increase in the US$ WTI benchmark price and a weaker Canadian dollar. Petrus realized an average negative oil differential of $7.33 in 2013, compared to a negative differential of $7.49 in 2012. The differential widened significantly in the fourth quarter, resulting in a realized negative differential of $14.79 in the fourth quarter of 2013 compared to a negative differential of $2.87 in the comparable period of the prior year.

Oil and condensate revenue for the fourth quarter of 2013 was $12.7 million and production of 163,576 bbl accounted for approximately 49% of total production volume and 75% of commodity revenue (compared to revenue of $8.0 million and production of 104,832 bbl for 42% of total production volume and 70% of commodity revenue in the fourth quarter of the prior year).

Oil and condensate revenue for the year ended December 31, 2013 was $43.4 million and production of 517,205 bbl accounted for approximately 44% of total production volume and 76% of commodity revenue (compared to revenue of $16.9 million and production of 213,525 bbl for 31% of total production volume and 67% of commodity revenue in the prior year).

Natural gas liquids (NGLs)

Petrus' NGL production mix consists of ethane, propane, butane, pentane and sulphur. The pricing received for Petrus' NGL production is based on the product mix, the fractionation process required and the demand for fractionation facilities. In the fourth quarter Petrus' NGL production decreased as a result of the operated Peace River facility turnaround. Petrus' overall realized NGL price averaged $67.20 per bbl compared to $64.33 per bbl in the prior year. NGL revenue for the fourth quarter of 2013 was $430,000 and production of 6,624 bbl accounted for approximately 2% of the Company's production volume and 3% of commodity revenue in the fourth quarter (compared to revenue of $437,000 and production of 6,822 bbl for 3% of total production and 4% of commodity revenue for the fourth quarter of the prior year).

NGL revenue for the year ended December 31, 2013 was $1.6 million and production of 25,550 bbl accounted for approximately 2% of the Company's production volume and 3% of commodity revenue in the fourth quarter (compared to revenue of $1.1 million and production of 17,155 bbl for 3% of total production and 4% of commodity revenue for the fourth quarter of the prior year).

Royalty Revenue

Petrus records gross overriding royalty revenue for production related to land or mineral rights owned. The revenue is included in "Other Income" on the Company's Statement of Net Income and Comprehensive Income. Royalty revenue received in the fourth quarter was $155,000 compared to $134,000 in the same quarter of the prior year. As noted the Company re-classified gross overriding royalty expense from other income to royalty expenses. The comparative information has been re-classified to conform to current presentation. For the year ended December 31, 2013 Petrus earned $620,000, an increase of 66% from $373,000 earned in the year ended December 31, 2012. The increase is attributed to higher commodity prices and additional wells drilled on the Company's royalty interest land.

NON-GAAP MEASURES

Petrus uses key performance indicators and industry benchmarks such as "cash flow from operations," "cash flow from operations per share," "cash flow from operations per debt-adjusted share," and "net debt" to analyze financial and operating performance. These indicators are not defined by IFRS and therefore may not be comparable to performance measures presented by other companies. Management believes that in addition to net income, the aforementioned non-IFRS measurements are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage and liquidity. Investors should be cautioned, however, that these measures should not be construed as an alternative to both net income and net cash from operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

Cash Flow from Operations

Cash flow from operations represents cash flow from operating activities prior to changes in non-cash working capital and settlement of decommissioning obligations. Petrus evaluates its financial performance primarily on cash flow from operations and considers it a key performance indicator as it demonstrates the Company's ability to generate sufficient cash flow to fund capital investment and repay debt. The reconciliation between cash flow from operations and cash flow from operating activities, as defined by IFRS, is as follows:

($000s)	**Twelve months ended Dec 31, 2013**	Twelve months ended Dec 31, 2012	**Three months ended Dec 31, 2013**	Three months ended Dec 31, 2012
Cash flow from operating activities	**26,238**	5,071	**7,079**	(43)
Changes in non-cash working capital	**4,853**	7,442	**2,141**	6,659
Cash flow from operations	**31,091**	12,513	**9,220**	6,616

Net Debt

Working capital (net debt) is a non-GAAP measure and is calculated as current assets (excluding financial derivative assets) less current liabilities (excluding financial derivative liabilities) and bank debt. Petrus uses net debt as a key indicator of its leverage and strength of its balance sheet. The reconciliation of net debt, as defined, is as follows:

($000s)	**As at Dec 31, 2013**	As at Dec 31, 2012
Current assets (excluding financial derivative assets)	**11,184**	23,828
Less: current liabilities (excluding financial derivative liabilities)	**(10,092)**	(21,002)
Less: bank debt	**(23,380)**	–
Working capital (net debt)	**(22,288)**	2,826

Debt-adjusted shares

Debt-adjusted shares are calculated by adding the shares outstanding for the relevant period to the share equivalent of the Company's net debt at end of period. The calculation assumes the debt is extinguished with a share issuance. Petrus is a privately held company with no public market pricing data. In order to determine the price to convert the Company's debt to shares, Petrus uses a six times debt-adjusted cash flow multiple on trailing quarter annualized cash flow. This multiple does not, in any way, indicate a fair value for Petrus' shares and the sole purpose is to show a comparative metric. Weighted average shares are used for the average quarterly and annual production metrics as well as for cash flow growth; end-of-period shares outstanding are used for exit production and reserves growth performance metrics. The table below reconciles the debt-adjusted shares for the average year-over-year cash flow growth performance metric.

($000s, except per share amounts)	**Twelve months ended Dec 31, 2013**	Twelve months ended Dec 31, 2012
Weighted average shares outstanding	**86,343**	61,377
Annualized cash flow from operations before interest	**37,164**	27,472
Share price to extinguish debt (1)	**2.32**	1.94
Ending net debt	**(22,288)**	2,793
Share equivalent on ending net debt	**9,592**	(1,438)
Debt-adjusted shares	**95,935**	59,923

(1) *Six times debt-adjusted cash flow multiple.*

CASH FLOW FROM OPERATIONS AND EARNINGS

Petrus generated cash flow from operations of $9.2 million during the quarter ended December 31, 2013 ($6.6 million during the fourth quarter of 2012). Commodity prices, natural gas in particular, improved materially from the fourth quarter of 2012. Natural gas (AECO) increased 10% from the fourth quarter of 2012 to the fourth quarter of 2013, and Edmonton crude increased 3% for the same period.

The Company's cash flow from operations increased 1.5 times from $12.5 million generated for the year in 2012 to $31.1 million for 2013. The increase is attributed to a 71% increase in total production year over year and a 34% increase in average commodity price for the year on a boe basis.

Net income increased to $2.1 million in the fourth quarter of 2013 (compared to a net loss of $706,000 in the fourth quarter of the prior year). The increase is due to an increase in production and commodity prices relative to the prior year. For the year ended December 31, 2013, Petrus reported net income of $8.1 million compared to $431,000 in the prior year. The following table provides detail on the Company's cash flow from operations on a barrel of oil equivalent ("boe") basis.

	Twelve months ended Dec. 31, 2013		Twelve months ended Dec. 31, 2012		Three months ended Dec. 31, 2013		Three months ended Dec. 31, 2012	
	$000s	$/boe	$000s	$/boe	$000s	$/boe	$000s	$/boe
Oil and natural gas revenue	57,435	49.08	25,139	36.53	16,939	50.33	11,372	45.19
Transportation	(2,136)	(1.83)	(811)	(1.18)	(543)	(1.61)	(277)	(1.10)
Net revenue	55,299	47.26	24,328	35.35	16,396	48.72	11,095	44.09
Royalty expense (1)	(8,964)	(7.66)	(3,502)	(5.10)	(2,372)	(7.05)	(1,856)	(7.38)
Royalty income (1)	620	0.53	373	0.54	155	0.46	134	0.53
Net oil and natural gas revenue	**46,955**	**40.13**	**21,198**	**30.80**	**14,179**	**42.13**	**9,373**	**37.25**
Operating expense (2)	(12,009)	(10.26)	(7,103)	(10.32)	(3,716)	(9.88)	(1,998)	(7.94)
Hedging gain (loss)	(1,311)	(1.12)	563	0.82	(409)	(1.21)	(142)	(0.56)
General & administrative	(1,856)	(1.59)	(1,885)	(2.74)	(582)	(1.73)	(546)	(2.17)
Interest expense (3)	(688)	(0.59)	(260)	(0.38)	(252)	(0.75)	(71)	(0.28)
Cash flow from operations	**31,091**	**26.56**	**12,513**	**18.18**	**9,220**	**28.56**	**6,616**	**26.30**

(1) The Company re-classified gross overriding royalty expense from oil and natural gas revenue to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.
(2) Operating expenses are presented net of processing income and overhead recoveries.
(3) Interest expense is presented net of interest income.

(000s except per share)	Twelve months ended Dec. 31, 2013	Twelve months ended Dec. 31, 2012	Three months ended Dec. 31, 2013	Three months ended Dec. 31, 2012
Cash flow from operations	**31,091**	**12,513**	**9,220**	**6,616**
Cash flow from operations/share	**0.36**	0.20	**0.11**	0.08
Net Income (loss)	**8,141**	**431**	**2,086**	**(706)**
Net income (loss)/share	**0.09**	0.01	**0.02**	(0.01)
Common shares	**86,377**	86,276	**86,377**	86,276
Weighted average shares	**86,343**	61,377	**86,377**	86,276

Performance Metrics

Petrus uses certain performance metrics as key indicators to demonstrate the Company's ability to generate shareholder value. On a debt-adjusted per share basis, Petrus increased cash flow from operations 55% year-over-year from 2012. The same metric for the fourth quarter-over-fourth quarter was an increase of 39%. Petrus increased exit production on a per debt-adjusted thousand share basis 26% from the prior year as shown in the table below:

	Twelve months ended Dec. 31, 2013	Twelve months ended Dec. 31, 2012	% Change	Three months ended Dec. 31, 2013	Three months ended Dec. 31, 2012	% Change
Cash flow from operations per debt-adjusted share[(1)] ($)	**$0.32**	$0.21	**55%**	**$0.11**	$0.08	**39%**
Exit production per debt-adjusted thousand shares[(1)] (boe per day)	**15.4**	12.3	**26%**	**—**	—	**—**

[(1)] Cash flow from operations per debt-adjusted share is a non-GAAP measure and is reconciled to the nearest GAAP measure on page 7 in the section heading "Non-GAAP" Measures.

RESULTS OF OPERATIONS

Royalty Expenses

Royalties are paid to the Government of Alberta and to gross overriding royalty owners. The following table shows the Company's quarterly royalty expenses by product category, based upon the primary product produced at the well.

Royalty Expenses ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Oil and NGLs ($000s)	**9,837**	3,973	**2,562**	1,927
% of production revenue	**22%**	11%	**20%**	11%
Natural gas (000s)	**1,822**	1,026	**409**	568
% of production revenue	**15%**	8%	**11%**	8%
Gas cost (allowance) (000s)	**(2,951)**	(1,534)	**(735)**	(640)
Gross overriding[(1)]	**256**	37	**136**	39
Total (000s)	**8,964**	3,502	**2,372**	1,894

[(1)] *The Company re-classified gross overriding royalty expense from oil and natural gas revenue to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.*

The increase in total royalties from the fourth quarter of 2012 ($1.9 million) to the fourth quarter of 2013 ($2.4 million) is the result of new production and an increased oil royalty rate paid for certain foothills production. The prolific Cordel wells drilled to date exceed the volume maximum of 50,000 bbls of oil in a short time period. As a result, some of the wells no longer qualify under the Alberta crown royalty incentive program and are subject to the maximum royalty rate of 40%. Total oil royalties paid in the quarter were $2.6 million, approximately 20% of production revenue ($1.9 million and 11% of production volume in the fourth quarter of 2012).

For the year ended December 31, 2013 Petrus recorded total royalties of $9.0 million compared to $3.5 million in the same period of 2012. The increase is directly related to the 71% increase in total production from the prior year. Furthermore certain new foothills production is subject to a gross overriding royalty and as a result the gross overriding royalty expense incurred in 2013 ($256,000) increased significantly from the prior year ($37,000).

Financial Instruments

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 has outstanding as at December 31, 2013:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
Jan. 1, 2014 to Mar. 31, 2014	Costless collar	4,000 GJ	$3.25 - $3.53/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	$3.55/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,500 GJ	$3.64/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	$3.70/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,500 GJ	$3.44/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	2,500 GJ	$3.61/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	$3.64/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,500 GJ	$3.65/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	2,000 GJ	$3.75/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	2,000 GJ	$3.81/GJ

Crude Oil Period Hedged	**Type**	**Daily Volume**	**Price (USD)**
Jan. 1, 2014 to Jun. 30, 2014	Fixed price	300 Bbl	WTI $95.90/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Put Option	200 Bbl	WTI $85.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $89.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	100 Bbl	WTI $92.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	200 Bbl	WTI $93.80/Bbl
Jan. 1, 2014 to Jun. 30, 2014	Fixed price	100 Bbl	WTI $96.05/Bbl
Jul. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $92.10/Bbl
Jul. 1, 2014 to Dec. 31, 2014	Fixed price	200 Bbl	WTI $94.05/Bbl

Electric Power Period Hedged	Type	Annual Volume	Price (CAD)
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	12,264 MW	$57.75/MWH
Jan. 1, 2015 to Dec. 31, 2015	Fixed price	12,264 MW	$50.00/MWH

Subsequent to December 31, 2013 the Company entered into the following financial derivative contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
Mar. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	$4.30/GJ
Mar. 1, 2014 to Mar. 31, 2014	Fixed price	500 GJ	$4.53/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	$3.99/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	500 GJ	$4.07/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	$4.32/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$3.84/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.04/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.10/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	500 GJ	$4.18/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.43/GJ

Crude Oil Period Hedged	Type	Daily Volume	Price
Mar. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $CAD105.20/Bbl
Aug. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $CAD103.05/Bbl
Jan. 1, 2015 to Dec. 31, 2015	Fixed price	200 Bbl	WTI $CAD100.00/Bbl

The impact of the contracts which were outstanding during the reporting periods are recorded as realized hedging gains (losses) and affect the Company's realized commodity price. The unrealized gain (loss) is recorded to demonstrate the impact of the outstanding contracts had they settled on the relative financial reporting period date. The contracts entered had the following impact on net income:

Other Income ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Realized hedging gain (loss)	**(1,311)**	563	**(409)**	(142)
Unrealized hedging gain (loss)	**(1,495)**	(770)	**11**	(2,237)
Total gain (loss) on derivatives	**(2,806)**	(207)	**(398)**	(2,469)

Strong commodity prices resulted in a fourth quarter realized hedging loss of $409,000, compared to a $142,000 loss realized in the same quarter of the prior year. The fourth quarter realized loss decreased the Company's realized price by $1.22 per boe, compared to a decrease in the prior year comparable period of $0.56 per boe. For the year ended December 31, 2013 Petrus recorded a $1.3 million loss on financial derivatives compared to a $563,000 gain recorded in the prior year. The change from 2012 to 2013 is due to the strengthening commodity price environment for oil and natural gas.

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 ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Operating expense, net	**12,009**	7,103	**3,716**	1,998
Operating expense, net ($ per boe)	**10.26**	10.32	**11.03**	7.94

Operating expenses totalled $3.7 million for the fourth quarter of 2013, an 85% increase from $2.0 million recorded in the same quarter of the prior year. The increase in aggregate net operating expenses is due to new production compared to the prior period.

For the year ended December 31, 2013, operating costs on a per boe basis were consistent with the prior year. New water disposal facilities in the Peace River area are expected to contribute to operating cost reductions in future periods.

Transportation Expenses

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

Transportation Expenses ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Transportation expense	**2,136**	811	**543**	277
$ per boe	**1.83**	1.18	**1.61**	1.10

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 totalled $543,000 or $1.61 per boe in the fourth quarter of 2013 ($277,000 or $1.10 per boe for the comparative period in the prior year). The increase in transportation costs is due to the higher reliance on trucking to deliver liquids production to sales points. Production volume increased and trucking costs on a per unit basis increased. Wait times at third party facilities rose as operators faced capacity constraints.

Transportation costs increased year over year from $1.18 per boe for the year ended December 31, 2012 to $1.83 per boe for the same period in 2013. The significant increase is due to increased trucking costs as well as pipeline facility constraints that led to higher volumes being trucked to sales delivery points.

General and Administrative Expenses

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

General and Administrative Expenses ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Gross general and administrative expense	**3,368**	2,829	**491**	966
Capitalized general and administrative	**(1,511)**	(944)	**91**	(420)
Net general and administrative expense	**1,856**	1,885	**582**	546
Share based compensation expense	**1,858**	2,071	**349**	645
Capitalized share based compensation	**(929)**	(972)	**(174)**	(323)
Total general and administrative expense, net	**2,786**	2,984	**756**	869

Fourth quarter 2013 net general and administration expenses (excluding non-cash share based compensation), totalled $582,000 or $1.73 per boe (compared to $546,000 or $2.17 per boe for the fourth quarter of 2012). Petrus capitalizes and reclassifies those general and administrative expenses which are directly attributable to the acquisition, exploration and development activities of the Company. In the fourth quarter Petrus reduced the capitalized component of G&A costs which resulted in an adjustment recorded in the fourth quarter of 2013. The 20% reduction in fourth quarter G&A costs on a per boe basis is attributed to G&A efficiencies as the production base grows.

For the year ended December 31, 2013, the Company's total G&A costs (including non-cash share based compensation) were consistent with prior year. As a result of the significant production increase from 2012 the total G&A costs on a per boe basis decreased 45% from $4.35 per boe in 2012 to $2.38 per boe in 2013.

Depletion and Depreciation

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

Depletion and Depreciation ($000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Depletion	**16,402**	7,630	**6,120**	5,423
Depreciation	**761**	459	**539**	174
Total	**17,163**	8,089	**6,659**	5,597
Depletion ($ per boe)	**14.02**	11.09	**18.19**	21.55
Depreciation ($ per boe)	**0.65**	0.67	**1.60**	0.69
Total ($ per boe)	**14.67**	11.75	**19.79**	22.24

Depletion and depreciation expense is calculated on a unit-of-production 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 costs. 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 2013 of $6.1 million or $18.19 per boe, compared to the fourth quarter of 2012, when $5.4 million or $21.55 per boe was recorded. For the quarter ended December 31, 2013, depreciation expense totalled $539,000, compared to $174,000 in the comparable quarter of the prior year. For the year ended December 31, 2013 Petrus recorded $17.2 million related to depletion and depreciation which represents a 112% increase from $8.1 million recorded in the prior year. The Company's depletion and depreciation have increased from prior year due to the increased production and reserves base.

Depletion and depreciation for the year ended December 31, 2013 increased 25% from the comparable period in 2012. The increase is due to the significant increase in the depletable base which relates to additions to petroleum and natural gas properties as well as future development cost estimates.

SHARE CAPITAL

The authorized share capital consists of an unlimited number of common voting shares without par value. The following table details the number of issued and outstanding instruments for the financial periods shown:

(000s)	**Twelve months ended Dec. 31, 2013**	Twelve months ended Dec. 31, 2012	**Three months ended Dec. 31, 2013**	Three months ended Dec. 31, 2012
Weighted average outstanding commons shares				
Basic	**86,343**	59,629	**86,377**	86,276
Diluted	**86,343**	59,629	**86,377**	86,276
Outstanding instruments				
Common shares	**86,377**	86,276	**86,377**	86,276
Stock options	**4,355**	3,995	**4,355**	3,995
Warrants	**6,423**	6,423	**6,423**	6,423

At April 11, 2014 the Company had 86,376,598 common shares outstanding. Subsequent to December 31, 2013 the Company issued 455,000 stock options. As at April 11, 2014 the Company had 4,810,000 and 6,422,603 stock options and performance warrants outstanding, respectively.

LIQUIDITY AND CAPITAL RESOURCES

The Company had a credit facility of $60 million with a major Canadian lender at December 31, 2013. The credit facility consisted of a $55 million demand revolver and a $5 million development line. The amount of the credit facility is subject to a borrowing base test performed on a semi-annual review by the lender, based primarily on reserves and using commodity prices estimated by the lender as well as other factors. The Company provided security by way of a $130 million debenture over all of the present and future acquired property of the Company. A decrease in the borrowing base could result in a reduction to the available credit facility.

At December 31, 2013, the Company did not have any letters of credit against the facility (December 31, 2012; $nil) and had drawn $23.4 million against the facility (December 31, 2012; nil). The Company has no drilling or other significant capital commitments.

Subsequent to December 31, 2013, Petrus entered into a purchase and sale agreement to acquire oil and natural gas assets from a working interest partner in the central Alberta foothills (the "Acquisition"). The Acquisition was made for total cash consideration of approximately $19.1 million (before post-closing adjustments) and closed February 28, 2014.

Concurrent with the closing of the acquisition, a semi-annual review of the credit facility took place on February 28, 2014 and the facility was increased to $90 million, comprised of an $80 million revolving credit facility and a $10 million development line. Subsequent to December 31, 2013, the Petrus Board of Directors approved a base capital budget of $74 million (before acquisitions) for 2014. The capital budget provides for the drilling of 36 gross (24 net) wells, with approximately $45 million directed at foothills development and $29 million directed toward the Peace River area. Concurrent with closing of the acquisition of foothills assets the capital budget increased to $100 million. The capital budget will be funded through cash flow and credit facilities.

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 cash flow, 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. Petrus anticipates that it will have adequate liquidity to fund future working capital and forecasted capital expenditures in 2013 through a combination of cash flow, current working capital and use of its credit facility. Petrus is able to modify its capital program in response to changes in commodity prices and cash flows. Should the Company choose to expand its capital program, actual funding alternatives will be influenced by the then current market environment and the ability to access capital on reasonable terms, balanced with the investment opportunities presented.

CAPITAL EXPENDITURES

Capital expenditures, excluding acquisitions and dispositions, totalled $9.7 million in the fourth quarter of 2013 compared to $21.5 million in the fourth quarter of the prior year. The majority of funds were invested in drilling and completions, construction of production facilities and tie-ins. During the year Petrus drilled 21 wells (11.4 net). Petrus invested $57.2 million (net of dispositions) in 2013, funded by cash flow from operations and the Company's revolving credit facility. The following table shows capital expenditures for the reporting periods indicated. All capital is presented before decommissioning obligations:

($000s)	Twelve months ended Dec. 31, 2013	Twelve months ended Dec. 31, 2012	Three months ended Dec. 31, 2013	Three months ended Dec. 31, 2012
Drill and complete	**44,259**	39,650	**3,844**	16,578
Oil and gas equipment	**9,129**	3,147	**3,616**	2,569
Geological	**698**	787	**97**	19
Land and lease	**2,177**	5,680	**1,421**	1,174
Office	**91**	980	**60**	374
Capitalized general and administrative	**2,497**	1,915	**698**	956
Total	**58,851**	52,159	**9,736**	21,457
Acquisitions/(dispositions)	**(1,701)**	59,630	**0**	-
Total capital	**57,150**	111,789	**9,736**	21,457
Gross (net) wells spud	**21 (11.4)**	23 (15.0)	**1 (0.3)**	10 (9.1)

RESERVES

The following table provides a summary of the Company's reserves, as evaluated by third party reserve engineers:

Reserves and Reserve Ratio Summary

	December 31, 2013[(1)]			December 31, 2012[(2)]		
Company Interest Reserves	**(MBoe)**	**FD&A[(3)]**	**RLI[(4)]**	**(MBoe)**	**FD&A[(3)]**	**RLI[(4)]**
Proved Producing	5,696	$34.72	4.9	5,190	$49.64	5.1
Total Proved	8,638	$31.38	7.4	7,690	$42.90	7.5
Total Proved +Probable	14,864	$21.57	12.7	12,301	$24.79	12.1
Net Present Value Discounted at 10%	**($000s)**			**($000s)**		
Proved Producing	88,804	—	—	71,336	—	—
Total Proved	127,454	—	—	90,923	—	—
Total Proved +Probable	228,083	—	—	149,484	—	—

[(1)]*The Company's December 31, 2013 reserves were evaluated by GLJ Petroleum Engineers and Sproule and Associates.*
[(2)]*The Company's December 31, 2012 reserves were evaluated by GLJ Petroleum Engineers.*
[(3)]*FD&A (finding, development and acquisition) cost is defined as capital costs for the time period including change in future development capital divided by change in reserves including revisions and production for that same time period.*
[(4)]*RLI (reserve life index) is defined as total reserves by category divided by the annualized fourth quarter production.*

In 2013 Petrus' total company interest reserves increased 21% to 14.9 mmboe on a proved plus probable ("P+P") basis and 12% on a total proved basis to 8.6 mmboe. The 2.9 mmboe net reserves addition in the company interest P+P category was accomplished at an all in finding, development and acquisition ("FD&A") cost of $21.57 per boe including future development capital ("FDC").

SUMMARY OF QUARTERLY RESULTS

	Three months ended							
($000s) except per share amounts	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sep 30, 2012	Jun. 30, 2012	Mar. 31, 2012
Oil and natural gas revenue	16,939	14,634	13,915	11,948	11,372	9,637	1,950	2,181
Transportation	(543)	(636)	(466)	(491)	(277)	(303)	(140)	(91)
Net revenue	16,396	13,998	13,449	11,457	11,095	9,334	1,810	2,090
Royalty expense (1)	(2,372)	(2,276)	(2.034)	(2,282)	(1,856)	(1,630)	503	(524)
Royalty income (1)	155	107	179	180	134	111	61	72
Net oil and natural gas revenue	14,179	11,829	11,594	9,355	9,374	7,815	2,374	1,638
Operating expense (2)	(3,716)	(2,460)	(2,753)	(3,080)	(1,998)	(3,236)	(1,259)	(607)
Hedging gain (loss)	(409)	(425)	(150)	(328)	(142)	270	242	193
General and administrative expense	(582)	(571)	(427)	(276)	(546)	(379)	(658)	(348)
Interest expense (3)	(252)	(216)	(216)	(5)	(71)	32	(194)	14
Cash flow from operations	9,220	8,157	8,048	5,666	6,616	4,502	505	890
Per share – basic/diluted	0.11	0.09	0.09	0.07	0.08	0.05	0.02	0.03
Net income (loss)	2,086	2,171	4,010	47	(706)	1,738	(2,060)	1,459
Per share – basic/diluted	0.02	0.03	0.05	0.01	(0.01)	0.02	(0.06)	0.05
Common shares (000s)	86,377	86,377	86,362	86,276	86,276	86,276	83,493	32,033
Weighted average shares (000s)	86,377	86,369	86,349	86,276	86,276	86,124	32,174	32,033
Total assets	211,952	201,208	199,507	184,139	181,976	167,438	153,422	62,836
Net working capital (net debt)	(22,288)	(21,558)	(15,756)	(10,551)	2,826	17,285	21,440	(2,241)

(1) The Company re-classified gross overriding royalty expense from other income to royalty expenses in the Statement of Net Income and Comprehensive Income. The comparative information has been re-classified to conform to current presentation.
(2) Operating expenses are presented net of processing income and overhead recoveries.
(3) Interest expense is presented net of interest income.

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 ("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.

ACCOUNTING POLICIES AND NEW STANDARDS

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, 2013.

New standards and interpretations not yet adopted
On January 1, 2013, the Company adopted the following new standards and amendments which became effective for periods on or after January 1, 2013:

IFRS 10 *Consolidated Financial Statements* builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where it is difficult to assess. IFRS 10 replaces those parts of IAS 27 *Consolidated and Separate Financial Statements* (revised 2011) that address when and how an entity should prepare consolidated financial statements and replaces SIC 12.

IFRS 11 *Joint Arrangements* provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form (as is currently the case). The standard addresses inconsistencies in the reporting of joint arrangements. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures* and SIC 13 *Jointly Controlled Entities – Non-Monetary Contributions by Ventures.* IAS 28 *Investments in Associates and Joint Ventures* (revised 2011) has been amended to conform to changes based on the issuance of IFRS 10 and IFRS 11.

IFRS 12 *Disclosure of Interests in Other Entities* requires extensive disclosures relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that help users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements. The effective date of IFRS 12 is January 1, 2013.

IFRS 13 *Fair Value Measurement* establishes a single framework for measuring fair values. This standard applies to all transactions and balances (whether financial or non-financial) for which IFRS requires or permits fair value measurements, with the exception of share-based payment transactions accounted for under IFRS 2 *Share-based Payment* and leasing transactions within the scope of IAS 17 *Leases*. IFRS 13 defines fair value, provides guidance on its determination and introduces consistent requirements for disclosures on fair value measurements.

Petrus has assessed the impact of adopting these pronouncements and has determined these standards did not have a material impact on the Company's financial statements.

In 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are to be adopted retrospectively for fiscal years beginning January 1, 2014. Petrus will adopt these amendments effective January 1, 2014. The adoption will impact disclosures in the notes to the financial statements only in periods when an impairment loss or impairment reversal is recognized.

Levies

In May 2013, the IASB issued IFRIC 21 Levies, which clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. No liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. Petrus is currently assessing whether these changes will have an effect on its financial statements.

Other accounting standards and interpretations

IFRS 9 *Financial Instruments* issued in November 2009 and amended in October 2010 introduces new requirements for the classification and measurement of financial assets and financial liabilities and for derecognition. IFRS 9 is expected to be published in three parts. The first part, Phase 1 – classification and measurement of financial instruments sets out the requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. Phase 1 simplifies the measurement of financial assets by classifying all financial assets as those being recorded at amortized cost or being recorded at fair value. Phase 1 is effective for periods beginning on or after January 1, 2015, although earlier adoption is allowed. Except for certain additional disclosures, the adoption of this standard is not expected to have an impact on the Company's financial statements.

ADVISORIES

Basis of Presentation

Financial data presented below have largely been derived from the Company's financial statement, prepared in accordance with 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, 2013. 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 document, including management's assessment of the Company's future plans and operations, 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 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; 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; treatment under governmental regulatory regimes and tax laws; estimated tax pool balances and anticipated IFRS elections and the impact of the conversion to IFRS. 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. However, 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*

Cover page photo credit: Alain Sleigher Photography

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Petrus Resources Ltd.:

We have audited the accompanying financial statements of Petrus Resources Ltd., which comprise the balance sheets as at December 31, 2013 and 2012, and the statements of net income (loss) and comprehensive income (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 financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Petrus Resources Ltd. as at December 31, 2013 and 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered accountants
Calgary, Canada
April 11, 2014

BALANCE SHEETS
(AUDITED)

(Expressed in Canadian dollars)

As at	December 31, 2013	December 31, 2012
ASSETS		
Current		
Cash	—	11,589,033
Deposits and prepaid expenses	303,101	589,566
Accounts receivable *(note 14)*	10,880,771	11,649,891
Risk management asset *(note 10)*	26,418	371,574
	11,210,290	**24,200,064**
Non-current		
Exploration and evaluation assets *(notes 5 and 6)*	50,528,518	45,790,854
Property, plant and equipment *(notes 5 and 7)*	150,212,756	111,985,145
	200,741,274	157,775,999
	211,951,564	**181,976,063**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Bank indebtedness *(note 8)*	23,379,651	—
Accounts payable and accrued liabilities	10,092,329	21,002,078
Risk management liability *(note 10)*	2,286,940	1,137,562
	35,758,920	**22,139,640**
Non-Current		
Decommissioning obligation *(note 9)*	15,546,813	12,395,714
Deferred income tax liability *(note 15)*	4,644,065	1,658,369
	55,949,798	**36,193,723**
Shareholders' Equity		
Share capital *(note 11)*	144,339,234	144,119,128
Contributed surplus	3,961,972	2,103,466
Retained earnings (deficit)	7,700,560	(440,254)
	156,001,766	**145,782,340**
	211,951,564	**181,976,063**

See accompanying notes to the financial statements
Commitments *(note 20)*

Approved by the Board of Directors,

(signed) "Don T. Gray"

Don T. Gray
Chairman

(signed) "Patrick Arnell"

Patrick Arnell
Director

STATEMENTS OF NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) (AUDITED)

(Expressed in Canadian dollars, except for share information)

	Year ended December 31, 2013	Year ended December 31, 2012
REVENUE		
Oil and natural gas revenue	**58,055,347**	**25,510,732**
Royalty expense	(8,963,869)	(3,501,921)
Oil and natural gas revenue, net of royalties	**49,091,478**	**22,008,811**
Other income	50,074	90,116
Gain (loss) on financial derivatives *(note 10)*	(2,805,500)	(206,662)
	46,336,052	**21,892,265**
EXPENSES		
Operating *(note 17)*	12,009,277	7,102,809
Transportation expenses	2,135,930	811,190
General and administrative *(note 18)*	1,856,245	1,885,007
Share-based compensation *(notes 11 and 18)*	929,253	1,099,242
Finance *(note 12)*	1,111,536	517,667
Exploration and evaluation expense *(note 6)*	—	420,000
Depletion and depreciation *(note 7)*	17,162,735	8,088,689
	35,204,977	**19,924,604**
NET INCOME (LOSS) BEFORE INCOME TAXES	**11,131,075**	**1,967,661**
Current tax expense	—	2,660
Deferred income tax expense *(note 15)*	2,990,261	1,534,062
	2,990,261	**1,536,722**
TOTAL NET INCOME AND COMPREHENSIVE INCOME	**8,140,814**	**430,939**
Net income per common share		
Basic and diluted	**0.09**	**0.01**

See accompanying notes to the financial statements

STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (AUDITED)

(Expressed in Canadian dollars)

	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total
Balance, December 31, 2011	**51,018,159**	**32,391**	**(871,193)**	**50,179,357**
Net income	—	—	430,939	430,939
Issuance of common shares *(note 11)*	95,160,000	—	—	95,160,000
Premium liability of flow-through shares	(215,422)	—	—	(215,422)
Share-based compensation expensed	—	1,099,242	—	1,099,242
Share-based compensation capitalized	—	971,833	—	971,834
Share issue costs	(2,914,580)	—	—	(2,914,580)
Tax benefit of share issue costs	876,400	—	—	876,400
Deferred tax benefits	194,571	—	—	194,570
Balance, December 31, 2012	**144,119,128**	**2,103,466**	**(440,254)**	**145,782,340**
Net income	—	—	8,140,814	8,140,814
Issuance of common shares *(note 11)*	215,540	—	—	215,540
Premium liability of flow-through shares	(13,610)	—	—	(13,610)
Share-based compensation expensed	—	929,253	—	929,253
Share-based compensation capitalized	—	929,253	—	929,253
Tax benefit of share issue costs	18,176	—	—	18,176
Balance, December 31, 2013	**144,339,234**	**3,961,972**	**7,700,560**	**156,001,766**

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS
(AUDITED)
(Expressed in Canadian dollars)

Funds generated by (used in):	**Year ended December 31, 2013**	**Year ended December 31, 2012**
OPERATING ACTIVITIES		
Net income (loss)	**8,140,814**	**430,939**
Adjust items not affecting cash:		
Share-based compensation	929,253	1,099,242
Unrealized hedging losses *(note 10)*	1,494,534	769,888
Finance expenses *(note 12)*	372,978	170,035
Exploration and evaluation expense *(note 6)*	—	420,000
Depletion and depreciation *(note 7)*	17,162,735	8,088,689
Deferred income tax expense *(note 15)*	2,990,261	1,534,062
	31,090,575	**12,512,856**
Change in operating non-cash working capital *(note 16)*	(4,852,774)	(7,441,454)
Funds generated by operations	**26,237,801**	**5,071,402**
FINANCING ACTIVITIES		
Issuance of common shares *(note 11)*	215,540	95,160,000
Share issue costs *(note 11)*	—	(2,914,580)
Increase in bank indebtedness	23,379,651	—
Change in financing non-cash working capital *(note 16)*	—	(979,856)
Funds generated by financing activities	**23,595,191**	**91,265,564**
INVESTING ACTIVITIES		
Property and equipment (acquisitions) dispositions *(note 7)*	1,701,319	(59,586,195)
Exploration and evaluation asset expenditures *(note 6)*	(5,197,494)	(16,979,120)
Petroleum and natural gas property expenditures *(note 7)*	(52,833,869)	(31,539,972)
Other capital expenditures	(90,592)	(765,295)
Change in investing non-cash working capital *(note 16)*	(5,001,389)	16,673,973
Funds used in investing activities	**(61,422,025)**	**(92,534,721)**
Increase (decrease) in cash	**(11,589,033)**	**3,802,245**
Cash, beginning of year	**11,589,033**	**7,786,788**
Cash, end of year	—	**11,589,033**
Cash interest paid	661,151	280,189
Cash taxes paid	—	2,660

See accompanying notes to the financial statements

NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF THE ORGANIZATION

Petrus Resources Ltd. ("Petrus" or the "Company") is a privately held entity which was incorporated under the laws of the Province of Alberta on December 13, 2010. These financial statements report the twelve months ended December 31, 2013 and were approved by the Company's Audit Committee April 11, 2014.

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. It conducts many of its activities jointly with others. These financial statements reflect only the Company's share of these jointly controlled assets and its proportionate share of the relevant revenue and related costs. The Company's head office is located at 2400, 240 – 4th Avenue SW, Calgary, Alberta Canada.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), interpretations of the International Financial Reporting Interpretations Committee ("IFRIC") and adopted by the Canadian Institute of Chartered Accountants ("CICA").

(b) Measurement Basis

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

(c) 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 ("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.

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. 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.

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.

Royalty income is recognized as it accrues in accordance with the terms of the respective overriding royalty agreements.
Other income is recognized as it is earned which includes interest income as well as processing income.

(b) 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, other directly attributable costs 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 bringing

in or enhancing production from such 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 income or loss.

Depletion and depreciation

The costs related to area cost centres 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 allocated to its CGU.

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 stated on the balance sheet at cost less accumulated depreciation. Depreciation is calculated on a reducing balance method so as to write off the cost of these assets, less estimated residual values, over their estimated useful lives. The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

Impairment

The carrying amounts of property, plant and equipment are grouped into CGU's and 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 assessment for impairment entails comparing the carrying value of the CGU with its recoverable amount: that is, the higher of fair value, less costs to sell, and value in use. Each CGU is identified in accordance with IAS 36, *Impairment of Assets*. Petrus' property, plant and equipment are grouped into CGU's 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 recoverable amount is the higher of fair value, less costs to sell, and the value-in-use. Fair value, less costs to sell, is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

Impairments of property, plant and equipment are only 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.

(c) 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).

Amortization

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.

Impairment

If and when facts and circumstances indicate that the carrying value of an exploration and evaluation asset may exceed its recoverable amount, an impairment review is performed. For exploration and evaluation assets, when there are such indications, an impairment test is carried out by grouping the exploration and evaluation assets with property, plant and equipment CGU's to which they belong for impairment testing. The equivalent combined carrying value of the CGU's is compared against the recoverable amount of the CGU's and any resulting impairment loss is written off to net income (loss). The recoverable amount is the greater of fair value, less costs to sell, or value-in-use.

(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 and depreciation 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 and accretion of the discount on decommissioning obligations.

(g) Financial instruments

Non-derivative financial instruments

Non-derivative financial instruments comprise cash and cash equivalents, accounts receivables, accounts payable and accrued liabilities and outstanding credit facilities. 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 cash equivalents are classified as financial assets at fair value, showing separately (i) those designated as such upon initial recognition and (ii) those classified as held for trading in accordance with IAS 39 *Financial Instruments: Recognition and Measurement*.
- Accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method. Typically, the fair value of these balances approximates their carrying value due to their short term to maturity.
- Accounts payable and accrued liabilities and outstanding credit facilities are classified as other liabilities and are measured at amortized cost using the effective interest method. Due to the short term nature of accounts payable and accrued liabilities, their carrying values approximate their fair values. The Company's outstanding credit facilities bear interest at a floating rate and accordingly the fair market value approximates the carrying value.

(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. The difference between the initial liability and the deferred tax liability created is recorded as a deferred tax expense.

(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. 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.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is expected to be settled or the asset realized, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which Petrus expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

(k) Joint interests

Petrus undertakes certain business activities through joint arrangements. A joint arrangement is established under contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control. Joint control is the contractually agreed sharing of control over an economic activity, and exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the parties sharing control.

(l) Share-based compensation

The Company follows the fair value method of valuing stock option and performance warrant grants. 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 fully diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of share warrants and stock options issued under the Company's Stock Option Plan would be used to purchase common shares at the average market price during the period. The treasury stock method also assumes that the deemed proceeds related to unrecognized share-based payments expense are used to repurchase shares at the average market price during the period. Under the treasury stock method, stock options and share warrants have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the options or warrants (they are "in-the-money"). Exercise of in-the-money stock options and share warrants is assumed at the beginning of the year or date of issuance, if later. Should the Company have a loss for the period, stock options and share warrants would be anti-dilutive and therefore will have no effect on the determination of loss per share.

(o) New standards and interpretations not yet adopted

On January 1, 2013, the Company adopted the following new standards and amendments which became effective for periods on or after January 1, 2013:

IFRS 10 *Consolidated Financial Statements* builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where it is difficult to assess. IFRS 10 replaces those parts of IAS 27 *Consolidated and Separate Financial Statements* (revised 2011) that address when and how an entity should prepare consolidated financial statements and replaces SIC 12.

IFRS 11 *Joint Arrangements* provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form (as is currently the case). The standard addresses inconsistencies in the reporting of joint arrangements. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures* and SIC 13 *Jointly Controlled Entities – Non-Monetary Contributions by Ventures.* IAS 28 *Investments in Associates and Joint Ventures* (revised 2011) has been amended to conform to changes based on the issuance of IFRS 10 and IFRS 11.

IFRS 12 *Disclosure of Interests in Other Entities* requires extensive disclosures relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that help users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements. The effective date of IFRS 12 is January 1, 2013.

IFRS 13 *Fair Value Measurement* establishes a single framework for measuring fair values. This standard applies to all transactions and balances (whether financial or non-financial) for which IFRS requires or permits fair value measurements, with the exception of share-based payment transactions accounted for under IFRS 2 *Share-based Payment* and leasing transactions within the scope of IAS 17 *Leases*. IFRS 13 defines fair value, provides guidance on its determination and introduces consistent requirements for disclosures on fair value measurements.

Petrus has assessed the impact of adopting these pronouncements and has determined these standards did not have a material impact on the Company's financial statements.

In 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are to be adopted retrospectively for fiscal years beginning January 1, 2014. Petrus will adopt these amendments effective January 1, 2014. The adoption will impact disclosures in the notes to the financial statements only in periods when an impairment loss or impairment reversal is recognized.

Levies

In May 2013, the IASB issued IFRIC 21 Levies, which clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. No liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. Petrus is currently assessing whether these changes will have an effect on its financial statements.

Other accounting standards and interpretations

IFRS 9 *Financial Instruments* – In November 2009, the International Accounting Standards Board ("IASB") issued IFRS 9 Financial Instruments to replace IAS 39 Financial Instruments: Recognition and Measurement. The standard was expanded in October 2010 and will be published in three phases, of which two phases have been published. The first phase replaces the current approach to classification and measurement of financial assets and liabilities and uses a model of only two classification categories: fair value or amortized cost. The second phase, amended in 2013 by the IASB, incorporates a new general hedge accounting model which will allow reporting entities more opportunities to apply hedge accounting. The third phase clarifies the use of a single impairment method when evaluating financial instruments. A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of phases one and two is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the 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, 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.

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 Statement of Financial Position 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 and interest rates.

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 the initial grant date.

The Company's financial instruments recorded at fair value 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 following tables provide fair value measurement information for financial assets and liabilities as of December 31, 2013. The carrying value of cash and cash equivalents, accounts receivables, deposits and accounts payables and accrued liabilities included in the Statement of Financial Position approximate fair value due to the short-term nature of those instruments. These assets and liabilities are not included in the following table.

	As at December 31, 2013				
	Carrying Amount	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Financial Assets					
Fair value of financial instruments	26,418	26,418	—	26,418	—
Financial Liabilities					
Fair value of financial instruments	2,286,940	2,286,940	—	2,286,940	—

5. ACQUISITIONS

On June 29, 2012 Petrus closed an acquisition of petroleum and natural gas assets in the Peace River area of Alberta, with an effective date of April 1, 2012, for total cash consideration of $60.3 million, net of adjustments and acquisition related expenses. 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 and was financed by existing cash balances and proceeds from an equity financing. A total of $72,243 in acquisition related costs, which relate to professional fees, have been charged to finance expenses in the Statement of Net Income and Comprehensive Income in the year ended December 31, 2012.

The financial statements incorporate the operations of the properties beginning June 30, 2012. During the period June 30, 2012 to December 31, 2012, the Company recorded oil and natural gas revenue of $11.3 million and net income of $6.3 million related to the acquisition. The impact of this acquisition on revenue and net income, as if acquired at the beginning of the year, would have been incremental revenue of $11.3 million and incremental net income of approximately $6.3 million.

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

Fair value of net assets acquired	
Prepaid operating expenses	568,271
Exploration and evaluation assets	5,612,500
Petroleum and natural gas properties and equipment	61,754,458
Decommissioning obligations	(7,652,684)
Total net assets acquired	**60,282,545**

6. EXPLORATION AND EVALUATION ASSETS

The components of the Company's Exploration and Evaluation assets are as follows:

Balance, December 31, 2011	**7,232,470**
Additions	42,693,416
Acquisitions (dispositions)	5,612,500
Capitalized G&A and share-based compensation	957,661
Decommissioning costs incurred	919,996
Transfers to property, plant and equipment	(11,625,189)
Balance, December 31, 2012	**45,790,854**
Additions	4,441,890
Acquisitions (dispositions)	—
Capitalized G&A and share-based compensation	1,220,230
Decommissioning costs incurred	—
Transfers to property, plant and equipment	(924,456)
Balance, December 31, 2013	**50,528,518**

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, 2013 the Company incurred exploration and evaluation expense in the Statement of Net Income and Comprehensive Income of $nil which relates to expiring undeveloped land in minor properties (2012 - $420,000).

During the year ended December 31, 2013 the Company capitalized $1.2 million (2012 - $957,661) of general & administrative expenses ("G&A") directly attributable to exploration activities. Included in this amount is non-cash share-based compensation of $464,626 (2012 - $485,917).

7. PROPERTY, PLANT AND EQUIPMENT

$	Cost	Accumulated DD&A	Net book value
Balance, December 31, 2011	**40,715,777**	**(626,733)**	**40,089,044**
Cash additions	5,647,482	—	5,647,482
Acquisitions (dispositions)	61,754,458		61,754,458
Capitalized G&A and share-based compensation	957,661	—	957,661
Transfers from exploration and evaluation assets	11,625,189	—	11,625,189
Depletion & depreciation	—	(8,088,689)	(8,088,689)
Change in decommissioning provision	—	—	—
Balance, December 31, 2012	**120,700,567**	**(8,715,422)**	**111,985,145**
Cash additions	52,168,855	—	52,168,855
Acquisitions (dispositions)	(1,901,319)	200,000	(1,701,319)
Capitalized G&A and share-based compensation	1,220,232	—	1,220,232
Transfers from exploration and evaluation assets	924,456	—	924,456
Depletion & depreciation	—	(17,162,735)	(17,162,735)
Change in decommissioning provision	2,778,122	—	2,778,122
Balance, December 31, 2013	**175,890,913**	**(25,678,157)**	**150,212,756**

Estimated future development costs of $58.8 million (2012 - $42.8 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, 2013 the Company capitalized $1.2 million (2012 - $957,661) of general & administrative expenses ("G&A") directly attributable to development activities. Included in this amount is non-cash share-based compensation of $464,627 (2012 - $485,916).

8. REVOLVING CREDIT FACILITY

The Company has a credit facility of $60 million with a major Canadian lender (see note 21). The credit facility consists of a $55 million demand revolver and a $5 million development line. The facility is available on a revolving basis for a period until June 29, 2014 and then for a further year under the term out provisions. The initial term out date may be extended for further 364 day periods at the request of Petrus, subject to approval by the lender. The credit facility provides that advances may be made by way of direct Canadian advances (at an interest rate equal to the Bank of Canada prime rate plus 0.75% per annum), U.S. dollar advances (at an interest rate equal to the U.S. Base Rate plus 0.75% per annum), or bankers' acceptances (at a stamping fee calculated on the face amount of the banker's acceptance at a rate equal to 175 basis points per annum).

The amount of the credit facility is subject to a borrowing base test performed on a semi-annual review by the lender, based primarily on reserves and using commodity prices estimated by the lender as well as other factors. The Company has provided security by way of a $130 million debenture over all of the present and after acquired property of the Company. A decrease in the borrowing base could result in a reduction to the available credit facility. A semi-annual review of the credit facility took place on February 28, 2014 and as noted in Note 21 the facility was increased to $90 million, comprised of an $80 million revolving credit facility and a $10 million development line. The next scheduled review will take place June 30, 2014. At December 31, 2013, the Company has no outstanding letters of credit against the facility (December 31, 2012; $180,000) and had drawn $23.4 million against the facility (December 31, 2012; nil).

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 three percent and an inflation rate of two percent (December 31, 2012; two percent and two percent, respectively). The Company has estimated the net present value of the decommissioning obligations to be $15.6 million as at December 31, 2013 ($12.4 million at December 31, 2012). The undiscounted, uninflated total future liability at December 31, 2013 is $19.7 million ($12.4 million at December 31, 2012). The payments are expected to be incurred over the operating lives of the assets. The following table reconciles the decommissioning liability:

Balance, December 31, 2011	3,652,999
Acquisitions	7,652,684
Liabilities incurred	919,996
Accretion expense	170,035
Balance, December 31, 2012	**12,395,714**
Dispositions	(80,000)
Liabilities incurred	749,308
Change in estimates	2,108,814
Accretion expense	372,977
Balance, December 31, 2013	**15,546,813**

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 has outstanding as at December 31, 2013 (see note 21):

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
Jan. 1, 2014 to Mar. 31, 2014	Costless collar	4,000 GJ	\$3.25 - \$3.53/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	\$3.55/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,500 GJ	\$3.64/GJ
Jan. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	\$3.70/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,500 GJ	\$3.44/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	2,500 GJ	\$3.61/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	\$3.64/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,500 GJ	\$3.65/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	2,000 GJ	\$3.75/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	2,000 GJ	\$3.81/GJ

Crude Oil Period Hedged	**Type**	**Daily Volume**	**Price (USD)**
Jan. 1, 2014 to Jun. 30, 2014	Fixed price	300 Bbl	WTI \$95.90/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Put Option	200 Bbl	WTI \$85.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI \$89.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	100 Bbl	WTI \$92.00/Bbl
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	200 Bbl	WTI \$93.80/Bbl
Jan. 1, 2014 to Jun. 30, 2014	Fixed price	100 Bbl	WTI \$96.05/Bbl
Jul. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI \$92.10/Bbl
Jul. 1, 2014 to Dec. 31, 2014	Fixed price	200 Bbl	WTI \$94.05/Bbl

Electric Power Period Hedged	**Type**	**Annual Volume**	**Price (CAD)**
Jan. 1, 2014 to Dec. 31, 2014	Fixed price	12,264 MW	\$57.75/MWH
Jan. 1, 2015 to Dec. 31, 2015	Fixed price	12,264 MW	\$50.00/MWH
Total risk management asset			26,418
Total risk management liability			2,286,940

For the twelve months ended December 31, 2013, Petrus recorded a realized loss of \$1.3 million and an unrealized loss of \$1.5 million (twelve months ended December 31, 2012 a realized gain of \$563,226 and an unrealized loss of \$769,888).

11. SHARE CAPITAL

Authorized

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

Issued and Outstanding

Common shares	Number of Shares	Amount
Balance, December 31, 2011	**32,033,017**	**51,018,159**
Common shares issued under private placement (a)	80,000	160,000
Common shares issued under private placement (b)	50,774,571	88,855,499
Common shares issued under private placement (d)	2,772,557	4,851,975
Flow-through shares issued, net of premium (c)	605,488	1,059,604
Flow-through shares issued, net of premium (d)	10,000	17,500
Share issue costs	—	(2,914,580)
Tax benefit of share issue costs	—	876,400
Deferred tax benefits	—	194,571
Balance, December 31, 2012	**86,275,633**	**144,119,128**
Common shares issued under private placement (e)	52,655	105,310
Flow-through shares issued, net of premium (e)	34,024	68,048
Tax benefit of share issue costs	—	18,176
Common shares issued under private placement (f)	14,286	28,572
Balance, December 31, 2013	**86,376,598**	**144,339,234**

Share Issuances

(a) In April 2012 the Company completed a subsequent closing to its November 2011 private equity placement and issued 80,000 common shares at a price of $2.00 per common share for gross proceeds of $160,000.

(b) The Company completed its third significant private equity placement on June 29, 2012. 50,774,571 common shares were issued at a price of $1.75 per share for gross proceeds of $88,855,499.

(c) On June 29, 2012, the Company also issued 605,488 flow-through shares at a price of $2.10 per share for total gross proceeds of $1,271,525. Of the issuance price, $0.35 per share or $211,921 was determined to be the premium on the flow-through shares. Petrus spent $1,059,604 on qualified exploration and development expenditures to satisfy the obligation.

(d) On July 5, 2012 the Company issued 2,772,557 common shares at a price of $1.75 per share for gross proceeds of $4.9 million. In addition, the Company issued 10,000 common shares on a flow-through basis at a price of $2.10 per share for gross proceeds of $21,000. Of the issuance price, $0.35 per share or $3,501 was determined to be the premium on the flow-through shares. The issuances were subsequent additional closings related to the June 2012 private equity placement.

(e) On April 26, 2013 the Company issued 52,655 common shares at a price of $2.00 per share and 34,024 flow-through shares at a price of $2.40 per share for total gross proceeds of $186,968. Of the issuance price, $0.40 per share or $13,610 was determined to be the premium on the flow-through shares. The issuance was made pursuant to an Exempt Offering which provided employees and key consultants an opportunity to purchase common and flow-through shares of the Company. Under National Instrument 45-102, the common shares issued are subject to a restricted hold period which expired August 27, 2013.

(f) On August 19, 2013 the Company issued 14,286 common shares at a price of $2.00 per share for gross proceeds of $28,572. The issuance was made pursuant to an Exempt Offering which provided employees and key consultants an opportunity to purchase common and flow-through shares of the Company. Under National Instrument 45-102, the common shares issued are subject to a restricted hold period which expires December 19, 2013.

SHARE-BASED COMPENSATION

Performance Warrants

The Company may issue performance warrants to employees, consultants and directors of the Company. Performance warrants are 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 warrants expire five years from the date of issuance. Upon exercise of the warrants the Company settles the obligation by issuing common shares of the Company and cash settlements are not required. 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 warrants granted shall not exceed 20% of the issued and outstanding shares as at April 30, 2012. At December 31, 2013, 6,422,603 (December 31, 2012; 6,422,603) performance warrants were issued.

	Number of warrants	Weighted Average Exercise Price ($)
Balance, December 31, 2011	**4,934,000**	**$2.00**
Granted	1,581,603	$2.00
Exercised	—	—
Forfeited or expired	93,000	$2.00
Balance, December 31, 2012	**6,422,603**	**$2.00**
Forfeited or expired	(417,000)	$2.00
Granted	417,000	$2.25
Balance, December 31, 2013	**6,422,603**	**$2.02**
Exercisable, December 31, 2013	**—**	**—**

During the year ended December 31, 2013 417,000 performance warrants were forfeited by the warrant holder. The warrants were distributed to new warrant holders later in the year. At December 31, 2013 there are no exercisable performance warrants given the market (one third vest as certain share price hurdles are achieved) criteria has not yet been met.

The following tables summarize information about the performance warrants granted since inception:

	Warrants Issued			Warrants Exercisable	
Grant date	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Number exercisable	Weighted average exercise price
December 19, 2011	4,934,000	$2.00	2.96	—	$2.00
March 20, 2012	400,000	$2.00	3.22	—	$2.00
May 1, 2012	400,000	$2.00	3.33	—	$2.00
September 5, 2012	225,000	$2.00	3.68	—	$2.00
July 10, 2012	56,603	$2.00	3.52	—	$2.00
August 6, 2012	400,000	$2.00	3.60	—	$2.00
November 5, 2012	100,000	$2.00	3.85	—	$2.00
November 14, 2013	417,000	$2.25	4.87	—	$2.25
	6,932,603	**$2.02**	**3.19**	**—**	**$2.02**

The fair value of each warrant granted of $0.24 (2012 - $0.25) per warrant is estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions (at December 31):

	2013	2012
Risk free interest rate	1.09%	1.23%
Expected life (years)	5	5
Estimated volatility of underlying common shares (%)	50%	50%
Estimated forfeiture rate	20%	20%
Expected dividend yield (%)	0%	0%

Petrus estimated the volatility of the underlying common shares by analyzing the volatility of peer group private companies with similar corporate structure, oil and gas assets and size. With respect to the market condition inherent in the warrants, Petrus estimated the probability of achieving the condition and applied the probability to each individual vesting tranche in order to fairly estimate the fair value of each warrant.

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 plan 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. At December 31, 2013, 4,355,000 stock options were issued. The summary of stock option activity is presented below:

	Number of stock options	Weighted Average Exercise Price ($)
Balance, December 31, 2011	—	—
Granted	3,995,000	$1.75
Balance, December 31, 2012	**3,995,000**	**$1.75**
Granted	584,000	$2.20
Forfeited or expired	224,000	$1.75
Balance, December 31, 2013	**4,355,000**	**$1.84**
Exercisable, December 31, 2013	**3,771,000**	**$1.75**

The following tables summarize information about the stock options granted since inception:

Stock Options Issued				
Grant date	Number granted	Weighted average exercise price	Weighted average remaining life (years)	Weighted average exercise price
June 29, 2012	3,600,000	$1.75	3.75	$1.75
July 10, 2012	65,000	$1.75	3.52	$1.75
August 27, 2012	175,000	$1.75	3.65	$1.75
November 5, 2012	155,000	$1.75	3.84	$1.75
March 18, 2013	99,000	$2.00	4.20	$2.00
June 3, 2013	10,000	$2.00	4.41	$2.00
November 14, 2013	160,000	$2.25	4.85	$2.25
December 31, 2013	315,000	$2.25	4.98	$2.25
	4,579,000	**$1.84**	**3.95**	**$1.84**

The fair value of each stock option granted of $0.79 (2012 - $0.77) per option is estimated on the date of grant using the Black-Scholes pricing model with the following weighted average assumptions (at December 31):

	2013	2012
Risk free interest rate	1.20%	1.20%
Expected life (years)	5	5
Estimated volatility of underlying common shares (%)	50%	50%
Estimated forfeiture rate	20%	20%
Expected dividend yield (%)	0%	0%

Petrus estimated the volatility of the underlying common shares by analyzing the volatility of peer group private companies with similar corporate structure, oil and gas assets and size.

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

Share-based compensation costs ($):	**Year ended December 31, 2013**	**Year ended December 31, 2012**
Expensed in net income	929,253	1,099,242
Capitalized to exploration and evaluation assets	464,626	485,917
Capitalized to property, plant and equipment	464,627	485,917
Total share-based compensation	**1,858,506**	**2,071,076**

12. FINANCE EXPENSES

The components of finance expenses are as follows:

	2013	2012
Cash:		
Interest	688,485	275,389
Acquisition related expenses *(note 5)*	—	72,243
		347,632
Non cash:		
Accretion on decommissioning obligations *(note 9)*	372,977	170,035
Total finance expenses	**1,061,462**	517,667

13. 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.

14. 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, 2013, 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 $10.9 million of accounts receivable outstanding at December 31, 2013 (December 31, 2012; $11.6 million), $5.0 million is owed from ten parties and was received subsequent to the quarter end (December 31, 2012 - $6.1 million from eight parties). As at December 31, 2013 and December 31, 2012, the majority of Petrus' accounts receivable were all aged less than 90 days and the Company had no past due receivables.

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, bank indebtedness, risk management liabilities and accrued 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, 2013, the Company had a $60 million credit facility, of which $36.6 million was undrawn (December 31, 2012, the Company had a $40 million credit facility which was entirely undrawn). Petrus anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future funds from operations and available bank debt.

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 revolving credit facility is exposed to interest rate cash flow risk as it is 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% change in the Canadian prime interest rate in the twelve months ended December 31, 2013 would have changed income by approximately $116,898, which relates to interest expense on the average outstanding revolving credit facility during the period, assuming that all other variables remain constant (twelve months ended December 31, 2012 – nil). The Company considers this risk to be limited.

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.

For the twelve months ended December 31, 2013, it is estimated that a $0.25/mcf change in the price of natural gas would have changed net income by $941,153 (twelve months ended December 31, 2012 - $554,770). For the twelve month period ended December 31, 2013, it is estimated that a $5.00/CDN WTI/bbl change in the price of oil would have changed net income by $2.6 million (twelve months ended December 31, 2012 - $686,120).

15. DEFERRED INCOME TAXES

	Year ended December 31, 2013	Year ended December 31, 2012
Income (loss) before taxes	**11,131,075**	**1,967,661**
Combined federal and provincial tax rate	25%	25%
Computed "expected" tax expense (recovery)	2,782,769	491,915
Increase/(decrease) in taxes resulting from:		
Permanent items	465,157	524,153
Tax impact of flow-through shares	—	597,638
Deferred tax benefits not previously recognized	—	(107,289)
Prior year true up	(222,864)	—
Change in rates	—	—
Part XXII.6 tax	—	2,660
Other	(34,802)	27,645
Current tax expense	—	**2,660**
Deferred tax expense	**2,990,260**	**1,534,062**
Effective tax rate	**26.9%**	**78.1%**

The components of the Company's deferred tax liability at December 31, 2013 and December 31, 2012 are as follows:

$	**Year ended December 31, 2013**	**Year ended December 31, 2012**
Net book value of assets in excess of tax pools	(13,655,088)	(9,763,312)
Asset retirement obligations	3,886,703	3,098,929
Share issuance costs	671,919	913,280
Non capital loss carry-forwards	3,887,270	3,901,138
Unrealized hedging gain	565,131	191,596
Deferred tax liability	**(4,644,065)**	**(1,658,369)**

The Company had non-capital losses of approximately $15,600,079 (2012 - $15,604,554) which may be applied against future income for Canadian tax purposes. These non-capital losses expire in 2031 and 2032.

16. SUPPLEMENTAL CASH FLOW INFORMATION

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

$	**Year ended December 31, 2013**	**Year ended December 31, 2012**
Source (use) in non-cash working capital:		
Accounts receivable	769,120	(8,014,533)
Deposits and prepaid expenses	286,466	(192,909)
Accounts payable and accrued liabilities	(10,909,749)	16,673,973
Risk management asset	-	(371,574)
Flow-through share premium liability	-	(979,856)
Risk management liability	-	1,137,562
	(9,854,163)	**8,252,663**
Operating activities	(4,852,774)	(7,441,454)
Financing activities	—	(979,856)
Investing activities	(5,001,389)	16,673,973

17. OPERATING EXPENSES

The Company's gross operating expenses for 2013 were $10.0 million (December 31, 2012; $9.3 million) which includes $2.9 million (December 31, 2012; $1.5 million) of processing, gathering and compression charges and $6.4 million (December 31, 2012; $8.0 million) of other operating expenses incurred to operate the Company's producing assets. The Company generated processing income recoveries of $683,697 (December 31, 2012; $2.2 million) which reduced the Company's reported operating expenses to $9.3 million for the year ended December 31, 2013 ($7.1 million for the year ended December 31, 2012).

18. GENERAL AND ADMINISTRATIVE EXPENSES

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

$	Year ended December 31, 2013	Year ended December 31, 2012
Salaries and benefits	1,885,285	1,892,848
Subscriptions and licenses	118,117	66,643
Office costs	673,659	504,901
Legal, accounting and consulting	690,394	364,105
Capitalized general and administrative	(1,511,209)	(943,490)
	1,856,245	**1,885,007**

19. KEY MANAGEMENT PERSONNEL

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

$	Year ended December 31, 2013	Year ended December 31, 2012
Salaries and wages	880,660	704,738
Short term employee benefits	26,100	19,442
Share based compensation, gross	1,435,286	1,381,246
	2,342,046	**2,105,426**

20. COMMITMENTS

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

Commitments (000s)	Total	< 1 year	1-5 years
Office equipment lease	10	3	7
Corporate office lease	1,052	502	550
Total commitments	**1,062**	**505**	**557**

21. SUBSEQUENT EVENTS

Business combination

On February 28, 2014 Petrus closed an acquisition of petroleum and natural gas assets in the central Alberta foothills, with an effective date of January 1, 2014, for total cash consideration of $19.1 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, will be charged to finance expenses in the Statement of Net Income and Comprehensive Income in the year ended December 31, 2014 as the transaction occurred subsequent to year end.

Concurrent with the closing of the asset acquisition on February 28, 2014, the Company's borrowing base was increased to $90 million, including a $10 million development line.

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

Fair value of net assets acquired	
Exploration and evaluation assets	5,446,050
Petroleum and natural gas properties and equipment	17,058,504
Decommissioning obligations	(3,391,360)
Total net assets acquired	**19,113,194**

Other subsequent events

On February 10, 2014 the Company granted 150,000 stock options at an exercise price of $2.25. On March 12, 2014 the Company granted 140,000 stock options at an exercise price of $2.50. On March 31, 2014 the Company granted 165,000 stock options at an exercise price of $2.50.

Subsequent to December 31, 2013 the Company entered into the following financial derivative contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
Mar. 1, 2014 to Mar. 31, 2014	Fixed price	1,000 GJ	$4.30/GJ
Mar. 1, 2014 to Mar. 31, 2014	Fixed price	500 GJ	$4.53/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	$3.99/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	500 GJ	$4.07/GJ
Apr. 1, 2014 to Oct. 31, 2014	Fixed price	1,000 GJ	$4.32/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$3.84/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.04/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.10/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	500 GJ	$4.18/GJ
Nov. 1, 2014 to Mar. 31, 2015	Fixed price	1,000 GJ	$4.43/GJ

Crude Oil Period Hedged	Type	Daily Volume	Price
Mar. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $CAD105.20/Bbl
Aug. 1, 2014 to Dec. 31, 2014	Fixed price	300 Bbl	WTI $CAD103.05/Bbl
Jan. 1, 2015 to Dec. 31, 2015	Fixed price	200 Bbl	WTI $CAD100.00/Bbl

CORPORATE INFORMATION

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