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NEWS RELEASE **May 3, 2017**

BLACKPEARL ANNOUNCES FIRST QUARTER 2017 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA – BlackPearl Resources Inc. ("BlackPearl" or the "Company") (TSX: PXX) (NASDAQ Stockholm: PXXS) is pleased to announce its financial and operating results for the three months ended March 31, 2017.

Highlights include:

- The Board of Directors sanctioned the expansion of our successful Onion Lake thermal project in Saskatchewan and construction began on the second 6,000 barrel per day phase of the project. Target date for completion of construction and first steam is mid-2018. Peak production rates are expected 9 to 12 months thereafter.

- Production averaged 10,753 barrels of oil equivalent (boe) per day, a 17% increase compared to Q1 2016 volumes. The increase is attributable to the production ramp-up on the Onion Lake thermal project, which produced 6,182 bbls/d in Q1 2017. Additionally, during the first quarter we re-started a portion of the alkali surfactant polymer (ASP) flood at Mooney.

- Oil and natural gas revenues increased 186% in the first quarter of 2017 to $37.2 million from $13.0 million in the same period in 2016.

- Net income in Q1 2017 was $7.8 million compared to a loss of $9.3 million in Q1 2016. Funds flow from operations increased to $12.9 million from $3.3 million in 2016.

- The Company maintained its strong financial position with no debt at the end of the quarter and positive working capital of $3.6 million.

- The Blackrod SAGD pilot continues to provide very positive results; over the last 24 months the pilot has produced an average of 550 bbls/d with a steam oil ratio under 3.

John Festival, President of BlackPearl commented “we are well underway with construction of phase two of our thermal project at Onion Lake. Equipment modules are over 50% complete and we expect to start field assembly and drilling in the summer. Our success with the first phase of the Onion Lake thermal project has shown that these long-life, lower cost thermal projects in Saskatchewan provide some of the best economics in industry even in a lower commodity price environment. This success has allowed us to grow our production and lower our cost structure and we expect this will continue with our expansion of thermal development at Onion Lake.”

Financial and Operating Highlights

	Three months ended March 31	
	2017	2016
Daily sales volumes		
Oil (bbl/d)	10,105	8,422
Bitumen (bbl/d) (1)	542	584
Combined	10,647	9,026
Natural gas (mcf/d)	638	845
Combined (boe/d) (2)	10,753	9,166
Product pricing ($)		
Crude oil - per bbl	40.75	16.77
Natural gas - per mcf	2.50	1.77
Combined - per boe	40.48	16.67
Operating netback ($/boe)		
Sales	40.48	16.67
Realized gains on risk management contracts	0.37	7.84
Subtotal	40.85	24.51
Royalties	5.90	1.72
Transportation costs	2.67	2.68
Operating costs	15.00	12.35
Netback (5)	17.28	7.76
($000's, except per share and boe amounts)		
Revenue		
Oil and gas revenue – gross	37,204	13,021
Net income (loss) for the period	7,814	(9,322)
Per share, basic and diluted	0.02	(0.03)
Funds flow from operations(3)	12,924	3,278
Cash flow from operating activities (4)	14,786	3,787
Capital expenditures	13,356	2,077
Working capital deficiency (surplus), end of period	(3,576)	(9,155)
Long term debt	-	86,000
Net debt (6)	(3,576)	76,845
Shares outstanding, end of period	336,195,568	335,638,226

(1) Includes production from the Blackrod SAGD pilot. All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.

(2) Boe amounts are based on a conversion ratio of 6 mcf of gas to 1 barrel of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

(4) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian

GAAP.

(5) Netback is a non-GAAP measure that does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

(6) Net debt is a non-GAAP measure that does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies.

Operations Review

<u>Onion Lake</u>

During the first quarter we commenced construction of the 6,000 bbl/d expansion of our thermal project. Similar to the first phase, we entered into a fixed sum contract for all of the major equipment modules for the central processing facilities and pad facilities. The fixed sum contract represents approximately 40% of the anticipated total costs of the expansion. These equipment modules are being built in a fabrication shop near Calgary and will be transferred to site when completed. Field construction and assembly of the equipment modules is expected to commence in the third quarter. In addition, during the first quarter we drilled water source wells which will be used to supply water for steam generation for the project and we began site preparation for the central processing facilities.

The thermal expansion at Onion Lake will utilize a combination of a modified SAGD process (using existing and new vertical wells as steam injectors and horizontal producers), which was used for phase one and the more traditional SAGD process (two horizontal wells drilled approximately 5 metres apart). The advantage of using vertical injectors is that it utilizes existing wellbores and provides us with the flexibility to steam upper hole zones at a later date. Initially, we are planning to drill 14 horizontal producer wells, three horizontal steam injector wells and 20 vertical injector/observation wells. Drilling these wells represent about 200 days of drilling time and is expected to commence in the summer.

The Company's target for initial steam injection for the second phase is mid-2018. Peak oil production rates are expected 12 months after commencement of steam injection, which is similar to what we experienced for the first phase of thermal development. Capital costs for the second phase of this thermal project are estimated to be between $180 and $185 million, which is approximately 20% lower than the construction costs for the first phase.

We are continuing to see excellent production results from the first phase of the Onion Lake thermal project. During the first quarter of 2017 oil production averaged nearly 6,200 bbl/d with a steam oil ratio (SOR) of 2.5. Cumulatively, the thermal project has produced in excess of three million barrels of oil. Oil production will be impacted during the second quarter as a result of a facility turnaround and inspection in May. In addition, during the drilling of the wells for the second phase of the project we will have to limit steam injection in nearby phase one wells which will also temporarily impact oil production volumes.

<u>Blackrod</u>

At Blackrod, we did not undertake any new activities during the first quarter of 2017; however, our existing SAGD pilot is continuing to perform exceptionally well. During Q1 2017, production from the pilot averaged 542 bbl/d. Over the last two years the pilot has produced an average of 550 bbl/d with an SOR under 3. Cumulatively, the SAGD well pair has produced over 525,000 barrels of oil. We are planning to continue to operate the pilot as we are still acquiring valuable technical and operational data that will be helpful designing a commercial project for the area.

We have commercial development approval for an 80,000 bbl/d project on our Blackrod lands. At current commodity prices, expansion of our Onion Lake project is economically more attractive than our other projects; however, our Blackrod lands contain significant amounts of oil and we are confident that as oil prices improve development of Blackrod will provide excellent long term value to our shareholders.

Mooney

At Mooney, as a result of the improvement in oil prices late last year and early in 2017 and changes to our operating procedures we decided to re-initiate the ASP (Alkalie, Surfactant, Polymer) flood over a portion of the phase one ASP flood lands. Operating costs tend to be higher for an ASP flood due to the cost of chemicals for injection and we had temporarily shut-in the ASP flood in early 2016 due to low commodity prices. During the quarter we restarted ASP injection in 20 horizontal wells. Production from the Mooney area increased in the first quarter as a result of the start-up of the flood; however, it is expected to take several months to see the full impact of the flood on Mooney production volumes. In total, we have 34 wells on production in the Mooney area.

Production

Oil and gas production averaged 10,753 barrels of oil equivalent per day in the first quarter of 2017, a 17% increase compared with the first quarter of 2016. The increase reflects the successful ramp-up of production from our Onion Lake thermal project.

Production in our non-thermal areas increased in the first quarter of 2017 compared to the fourth quarter of 2016. With the improvement in crude oil prices we selectively brought back on production several shut-in wells at Onion Lake and re-initiated a portion of the ASP flood at Mooney. At Onion Lake, we still have approximately 500 barrels of oil per day currently shut-in.

Average Daily Sales Volume

Production by area (boe/d)	**Q1 2017**	Q4 2016	Q1 2016
Onion Lake - thermal	**6,182**	6,119	4,252
Onion Lake - conventional	**2,147**	2,011	2,232
Mooney	**942**	785	1,042
John Lake	**808**	837	861
Blackrod	**542**	523	584
Other	**132**	204	195
	10,753	10,479	9,166

Financial Results

Oil and natural gas sales increased 186% in the first quarter of 2017 to $37.2 million from $13.0 million in the same period in 2016. The increase in oil and gas sales is attributable to a 143% increase in average sale price received and a 17% increase in production volumes (on a boe basis).

Our realized oil price (before the effects of risk management activities) in Q1 2017 was $40.75 per barrel compared to $16.77 per barrel in 2016. The increase in our realized wellhead price reflects higher WTI oil prices in Q1 2017 compared with Q1 2016 (US$51.91/bbl vs US$33.45/bbl), partially offset by a stronger Canadian dollar relative to the US dollar ($0.756 vs $0.727) and slightly wider heavy oil differentials (US$14.61/bbl vs US$14.32/bbl).

During the first quarter we also realized a small gain of $0.3 million from our oil hedging program, which was the equivalent of adding $0.37 per barrel to our wellhead price in the quarter. The following summarizes the hedging contracts we currently have outstanding:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap
Oil	500 bbls/d	April 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar
Oil	1,000 bbls/d	April 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap
2018					
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call

Total production costs increased 43% in the first quarter of 2017 to $13.8 million from $9.6 million in the same period in 2016. On a per boe basis, total production costs increased 21% in the first quarter of 2017 to $15.00 per boe from $12.35 per boe in the same period in 2016.

Thermal production costs at Onion Lake were fairly consistent between the first quarter of 2017 and the fourth quarter of 2016. During the first quarter of 2017 thermal production costs averaged $8.85 per barrel compared with $8.35 per barrel in Q4 2016 and $10.58 per barrel in Q1 2016.

The increase in total production costs during the first quarter of 2017 was primarily attributable to an increase in production costs on our non-thermal properties. The re-initialization of the ASP flood at Mooney resulted in an increase in chemical and injection costs during the quarter. In addition, we incurred workover costs on the wells we restarted at Mooney and Onion Lake. During the first quarter of 2017 production costs on our non-thermal properties averaged $24.43 per barrel compared with $18.59 per barrel in Q4 2016 and $14.09 per barrel in Q1 2016. Operating costs on our non-thermal properties are expected to decrease during the remainder of the year as our workover activities return to normal levels.

Funds flow from operations in Q1 2017 was $12.9 million compared with $3.3 million in the first quarter of 2016. The increase reflects significantly higher revenues partially offset by higher royalties, operating costs and G&A costs. Net income for the quarter was $7.8 million compared to a loss of $9.3 million in Q1 2016.

Capital spending was $13.4 million during Q1 2017, with the majority of costs spent on the expansion of the Onion Lake thermal project. In addition, during the quarter we sold some minor non-producing assets for proceeds of $3.4 million.

At March 31, 2017, the Company had no bank debt and had working capital of $3.6 million. The total credit facilities available to the Company are currently $117.5 million. The lenders next review of these facilities will be completed by May 31, 2017.

Outlook - Guidance

Our plan for the remainder of 2017 is relatively unchanged with the focus being the expansion of the Onion Lake thermal project with a target completion date of mid-2018. We are planning to spend between $185 and $190 million on capital projects, down from our initial guidance of $200 million. The decrease in capital spending is the result of deferring drilling on some our conventional heavy oil projects at John Lake, Onion

Lake and other minor project areas to future periods, as well as adjusting the timing of expenditures on the Onion Lake thermal expansion.

The capital program is expected to be funded from a combination of our anticipated funds flow from operations and our undrawn credit facilities. We are also looking to supplement these sources with additional term debt financing to provide us with financial flexibility during the construction phase. Funds flow from operations is expected to be between $55 and $60 million, down from our initial guidance of $65 to $70 million. The decrease in funds flow from operations reflects a change in the average wellhead price we expect to receive for the remainder of the year. Year-end 2017 debt levels are anticipated to be between $130 and $135 million, down from our initial guidance of $135 and $140 million. The decrease in year-end debt levels reflects a decrease in capital spending for the remainder of the year. We anticipate oil and gas production to average between 10,000 and 11,000 boe/d in 2017, unchanged from our initial guidance.

The 2017 first quarter report to shareholders, including the financial statements, management's discussion and analysis and notes to the financial statements are available on the Company's website (www.blackpearlresources.ca) or SEDAR (www.sedar.com).

Non-GAAP Measures

Throughout this release, the Company uses terms "funds flow from operations", "operating netback" and "net debt". These terms do not have any standardized meaning as prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Management utilizes funds flow from operations as a key measure to assess operating performance and the ability of the Company to finance operating activities, capital expenditures and debt repayments. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The following table reconciles non-GAAP measure funds flow from operations to cash flow from operating activities, the nearest GAAP measure.

	Three months ended March 31,	
($000s)	2017	2016
Cash flow from operating activities	14,786	3,787
Add (deduct):		
Decommissioning costs incurred	42	147
Changes in non-cash working capital related to operations	(1,904)	(656)
Funds flow from operations	12,924	3,278

Operating netback is calculated as oil and gas revenues less royalties, production costs and transportation costs on a dollar basis and divided by total production for the period on a boe basis. Oil and gas revenues exclude the impact of realized gains on risk management contracts. Operating netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis. Our operating netback calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation (COGE) Handbook.

Net debt is calculated as long-term debt plus working capital for the period ended. Working capital consists of cash and cash equivalents, trade and other receivables, inventory, prepaid expenses and deposits, fair value of risk management assets less accounts payable and accrued liabilities, current portion of decommissioning liabilities, deferred consideration and fair value of risk management liabilities. Management utilizes net debt as a key measure to assess the liquidity of the Company.

Forward-looking Statements

This release contains certain forward-looking statements and forward-looking information (collectively referred to as **“forward-looking statements”**) within the meaning of applicable Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. Forward-looking statements are typically identified by such words as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "potential", "targeting", "intend", "could", "might", "should", "believe" or similar words suggesting future events or future performance.

In particular, this release contains forward-looking statements pertaining to the estimated capital costs of between $180 to $185 million to construct phase 2 of the Onion Lake thermal project and the estimated mid-2018 completion date and estimated timing to reach peak production rates, estimated timing to see the full impact on production of the re-initiation of the ASP flood at Mooney, anticipated debt funding for the Phase 2 thermal expansion at Onion Lake and all the information under *Outlook – Guidance*.

The forward-looking information is based on, among other things, expectations and assumptions by management regarding its future growth, future production levels, future oil and natural gas prices, continuation of existing tax, royalty and regulatory regimes, foreign exchange rates, estimates of future operating costs, timing and amount of capital expenditures, performance of existing and future wells, recoverability of the Company’s reserves and contingent resources, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment on a timely and cost efficient basis, general economic and financial market conditions, environment matters and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.
By their nature, forward-looking statements involve numerous known and unknown risks and uncertainties that contribute to the possibility that actual results will differ from those anticipated in the forward looking statements. These risks include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, volatility of commodity inputs, substantial capital requirements, conditions including receipt of necessary regulatory and stock exchange approvals with respect to the issuance of common shares, uncertainties inherent in estimating quantities of reserves and resources, extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, financial loss associated with derivative risk management contracts, potential cost overruns, variations in foreign exchange rates, variations in interest rates, diluent and water supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, uncertainties inherent in the SAGD bitumen and ASP recovery process, credit risks associated with counterparties, the failure of the Company or the holder of licences, leases and permits to meet requirements of such licences, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate abandonment and reclamation costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company’s assets, geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. Readers are also cautioned that the foregoing list of factors is not exhaustive. Further information regarding these risk factors may be found under “Risk Factors” in the Annual Information Form.

Undue reliance should not be placed on these forward-looking statements. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the differences may be material and adverse to the Company and its shareholders. Furthermore, the forward-looking statements contained in this release are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

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The information in this release is subject to the disclosure requirements of the Company under the EU Market Abuse Regulation and the Swedish Securities Markets Act. The information was publicly communicated on May 3, 2017 at 3:00 p.m. Mountain Time.

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three months ended March 31, 2017. These results are being compared with the three months ended March 31, 2016. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended March 31, 2017, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2016.

All dollar amounts are referenced in thousands of Canadian dollars, except where otherwise noted. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS), as is required under Canadian generally accepted accounting principles (GAAP).

Throughout this MD&A the calculation of barrels of oil equivalent (boe) is based on a conversion rate of six thousand cubic feet (mcf) of natural gas to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and is not intended to represent a value equivalence at the wellhead.

The following is a summary of the abbreviations that may have been used in this document:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	MMBtu	million british thermal units
boe	barrel of oil equivalent	GJ	gigajoule
boe/d	barrel of oil equivalent per day		
WTI	West Texas Intermediate (a light oil reference price)		
WCS	Western Canadian Select (a heavy oil reference price)		
SAGD	Steam Assisted Gravity Drainage (a thermal recovery process)		
ASP	Alkali, Surfactant, Polymer		
EOR	Enhanced Oil Recovery		
EBITDA (adjusted)	Comprehensive income (loss) before income tax, financing charges, non-cash items, unrealized gain or losses on risk management contracts and income/loss attributed to assets acquired or disposed as defined in the Company's lending agreement.		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "operating netback" and "net debt". These terms do not have any standardized meaning as prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Management utilizes funds flow from operations as a key measure to assess operating performance and the ability of the Company to finance operating activities, capital expenditures and debt repayments. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The following table reconciles non-GAAP measure funds flow from operations to cash flow from operating activities, the nearest GAAP measure.

($000s)	**Q1 2017**	Q4 2016	Q1 2016
Cash flow from operating activities (1)	**14,786**	15,079	3,787
Add (deduct):			
Decommissioning costs incurred	**42**	26	147
Changes in non-cash working capital related to operations	**(1,904)**	693	(656)
Funds flow from operations (2)	**12,924**	15,798	3,278

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Funds flow from operations is a non-GAAP measure. Funds flow from operations does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Operating netback is calculated as oil and gas revenues less royalties, production costs and transportation costs on a dollar basis and divided by total production for the period on a boe basis. Oil and gas revenues exclude the impact of realized gains on risk management contracts. Operating netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis. Our operating netback calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation (COGE) Handbook.

Net debt is calculated as long-term debt less working capital for the period ended. Working capital consists of cash and cash equivalents, trade and other receivables, inventory, prepaid expenses and deposits, fair value of risk management assets less accounts payable and accrued liabilities, current portion of decommissioning liabilities, deferred consideration and fair value of risk management liabilities. Management utilizes net debt as a key measure to assess the liquidity of the Company. The following table reconciles non-GAAP measure net debt to long-term debt, the nearest GAAP measure.

($000s)	**March 31, 2017**	December 31, 2016
Long-term debt (1)	**-**	-
Add (deduct) working capital:		
Cash and cash equivalents	**(9,603)**	(5,368)
Trade and other receivables	**(13,892)**	(13,391)
Inventory	**(151)**	(46)
Prepaid expenses and deposits	**(702)**	(705)
Accounts payable and accrued liabilities	**19,609**	17,950
Current portion of decommissioning liabilities	**559**	644
Current portion of deferred consideration	**371**	404
Fair value of risk management liabilities	**233**	5,507
Net debt (surplus) (2)	**(3,576)**	4,995

(1) Long-term debt is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Net debt (surplus) is a non-GAAP measure. Net debt does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Management believes the presentation of the non-GAAP measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze the performance against prior periods on a comparable basis.

Additional information relating to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

This MD&A contains forward-looking information and statements. At the end of this MD&A is an advisory on forward-looking information and statements.

The effective date of this MD&A is May 3, 2017.

OVERVIEW

BlackPearl is a Canadian-based oil and natural gas company whose common shares are traded on the Toronto Stock Exchange (TSX) under the symbol "PXX". The Corporation's Swedish Depository Receipts trade on the NASDAQ Stockholm Exchange under the symbol "PXXS". BlackPearl's primary focus is on heavy oil and oil sands projects in Western Canada.

BlackPearl's current core properties are:

- Onion Lake, Saskatchewan – a conventional heavy oil property as well as a multi-phase thermal project. The first phase of the thermal project was put on production in 2015 and the second phase is currently under construction and is expected to be completed mid-2018;
- Mooney, Alberta – a conventional heavy oil property currently developed using both horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property, in the exploration and evaluation phase, located in the Athabasca oil sands region of which the Company is currently operating a pilot project using the SAGD recovery process.

These core properties provide the Company with a combination of short-term cash flow generation and medium and longer-term reserves and production growth on multi-phase low decline projects using both EOR and SAGD thermal recovery processes.

2017 SIGNIFICANT EVENTS

- During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Total estimated capital costs for the project are between $180 and $185 million and the project is expected to be completed in mid-2018. The Company has entered into a fixed price agreement to fabricate the central processing facilities and pad facilities for this second phase, which represents approximately 40% of the total estimated capital costs.

- In the first quarter of 2017, WTI oil prices averaged US$51.91 per bbl compared to US$33.45 per bbl in the first quarter of 2016.

- During the first quarter of 2017, oil and gas production averaged 10,753 boe/d; a 17% increase compared to the same period in 2016. The increase was mainly attributable to the first phase of the Onion Lake thermal project. During the first quarter of 2017, production from this project averaged 6,182 bbls/d, with a steam to oil ratio of 2.52.

- Capital expenditures during the first quarter were $13.4 million, with approximately $8.9 million spent at the Onion Lake thermal project related to construction of the second phase of the project, $1.9 million spent at John Lake related to the drilling of two horizontal heavy oil wells, $1.6 million at Mooney related to bringing shut-in production back online and $1.0 million spent in other areas. The Company also completed dispositions of non-producing properties for proceeds totaling $3.4 million during the first quarter.

- Oil and gas sales during the first quarter increased 186% to $37 million and funds flow from operations (a non-GAAP measure) were $13 million. For the quarter ended March 31, 2017, the Company recognized net income of $7.8 million.

- During the first quarter of 2017, 246,673 common shares were issued pursuant to the exercise of stock options which generated net proceeds of $0.2 million for the Company. The Company did not undertake any equity issuances during the first quarter.

- At March 31, 2017, BlackPearl had working capital of $3.6 million and no bank debt, leaving $117.5 million available to be drawn under the Company's existing credit facilities.

SELECTED QUARTERLY INFORMATION

	2017	2016				2015		
($000s, except where noted)	**Mar 31**	**Dec 31**	**Sep 30**	**Jun 30**	Mar 31	Dec 31	Sep 30	Jun 30
Production (boe/d) [(1)]	**10,753**	**10,479**	**10,951**	**9,698**	9,166	9,521	7,478	8,051
Oil and gas sales	**37,204**	**35,360**	**32,367**	**28,318**	13,021	22,630	20,814	30,712
Oil sales ($/bbl)	**40.75**	**38.83**	**34.15**	**34.44**	16.77	27.65	35.02	47.52
Gas sales ($/mcf)	**2.50**	**2.90**	**2.10**	**1.29**	1.77	2.91	2.88	2.61
Oil and gas sales ($/boe)	**40.48**	**38.61**	**33.87**	**34.03**	16.67	27.45	34.05	45.37
Production & transportation costs	**16,233**	**13,550**	**13,603**	**12,246**	11,736	15,666	12,843	14,245
Production costs ($/boe)	**15.00**	**12.11**	**12.13**	**13.23**	12.35	17.77	20.04	19.86
Transportation costs ($/boe)	**2.67**	**2.69**	**2.11**	**1.48**	2.68	1.23	0.97	1.18
Gain (loss) on risk management contracts								
Realized	**342**	**578**	**2,137**	**1,958**	6,120	10,334	7,940	5,245
Unrealized	**5,569**	**(5,676)**	**(538)**	**(8,597)**	(472)	1,778	11,826	(13,533)
Net income (loss)	**7,814**	**(2,217)**	**556**	**(8,945)**	(9,322)	(31,172)	5,402	(10,079)
Per share, basic and diluted ($)	**0.02**	**(0.01)**	**0.00**	**(0.03)**	(0.03)	(0.09)	0.01	(0.03)
Capital expenditures	**13,356**	**6,150**	**1,753**	**945**	2,077	1,665	7,870	15,992
Funds flow from operations [(2)]	**12,924**	**15,798**	**14,202**	**11,497**	3,278	10,898	10,156	14,968
Cash flow from operating activities	**14,786**	**15,079**	**16,441**	**7,184**	3,787	12,179	14,216	12,100
Long-term debt	**-**	**-**	**67,000**	**80,000**	86,000	88,000	97,000	94,000
Total assets (end of period)	**737,735**	**732,404**	**773,206**	**782,591**	795,336	808,344	861,107	864,926
Shares outstanding (000s)	**336,196**	**335,949**	**335,647**	**335,647**	335,638	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	**336,157**	**335,733**	**335,646**	**335,641**	335,638	335,638	335,638	335,638
Diluted	**340,700**	**340,686**	**337,959**	**335,641**	335,638	335,638	335,638	335,638

(1) Includes test production from the Blackrod SAGD pilot. All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.

(2) Funds flow from operations is a non-GAAP measure. Funds flow from operations does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Fluctuations in quarterly oil and gas sales and net income (loss) over the last eight quarters are primarily attributable to the volatility in crude oil prices and changes in sales volumes from new drilling activity, partially offset by natural declines in production. Production volumes in Q4 2015 increased as a result of the start-up of commercial production from the first phase of the Onion Lake thermal project. The net loss incurred in Q4 2015 is mainly attributable to an impairment charge of $33 million taken on our Mooney CGU.

BUSINESS ENVIRONMENT

Fluctuations in commodity prices have a significant influence on BlackPearl's results of operation and financial condition. The following table shows selective market benchmark prices and foreign exchange rates to assist in understanding how these factors impact our performance.

Commodity Prices

	2017	2016				2015		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US$/bbl)	51.91	49.29	44.94	45.59	33.45	42.18	46.43	57.94
Western Canadian Select (WCS) (Cdn$/bbl)	49.36	46.62	41.02	41.61	26.31	36.86	43.27	56.95
Differential – WCS/WTI (US$/bbl)	14.61	14.34	13.51	13.30	14.32	14.57	13.39	11.62
Differential - WCS/WTI (%)	28.1%	29.1%	30.1%	29.2%	42.8%	34.5%	28.8%	20.1%
Average Natural Gas Prices								
AECO gas (Cdn$/GJ)	2.55	2.93	2.20	1.33	1.74	2.34	2.75	2.52
Average Foreign Exchange (US$ per Cdn$1)	0.756	0.750	0.766	0.776	0.727	0.749	0.764	0.813

Crude oil prices are based on supply and demand for oil which is generally tied to global economic growth, but is also influenced by other factors such as political instability, market uncertainty, weather conditions, infrastructure constraints and government regulations. Crude oil in North America is commonly priced relative to the price of WTI oil, a light sweet crude with API gravity of about 40 degrees. Virtually all of BlackPearl's production is heavy oil and bitumen and is typically priced relative to the Western Canadian Select oil price, which has an average gravity of about 20.5 degrees API.

During the first quarter of 2017, oil prices improved as WTI averaged US$51.91 per bbl compared to US$49.29 per bbl in the fourth quarter of 2016 and US$33.45 per bbl in the first quarter of 2016. The increase in the first quarter crude oil pricing has been attributed to improving global demand for oil and the decision made late last year by the Organization of Petroleum Exporting Countries (OPEC) and certain non-OPEC countries to reduce their oil output by approximately 1.8 million bbls/d.

The heavy oil differential (WTI oil prices compared to WCS oil prices) was relatively flat in the first quarter of 2017 averaging US$14.61 per bbl compared to US$14.32 per bbl in the same period in 2016; however, heavy oil differentials as a percentage of WTI prices narrowed to 28.1% in the first quarter of 2017 compared to 42.8% in the same period in 2016. More recently, we have seen heavy oil differentials narrow in the second quarter of 2017 as a result of temporarily shut-in heavy oil production in Canada and decreased US imports of heavier grades of oil from OPEC due to their decision to reduce oil output, resulting in greater demand for Canadian heavy oil.

Natural gas prices decreased in the first quarter of 2017 averaging $2.55/GJ compared to $2.93/GJ in the fourth quarter of 2016 but increased compared to $1.74/GJ in the first quarter of 2016. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current revenues. However, we do consume relatively large amounts of gas in our Blackrod pilot operations and at our Onion Lake thermal project with fluctuations in natural gas prices having a significant effect on our costs in these areas.

Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by reference to US benchmark prices. The Canadian dollar improved against the US dollar in the first quarter of 2017 which partially mitigated the effect of higher crude oil prices on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.76 during the first quarter of 2017 compared to Cdn$1 = US$0.73 in the first quarter of 2016.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently showing the effect of the change of one variable, with all other variables being held constant.

Estimated change in annualized funds flow from operations for 2017 (1) (2):

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	1,434
Realized crude oil price (Cdn$/bbl)	1.00	2,279
US $ to Canadian $ exchange rate	0.01	850

(1) This analysis assumes current royalty rates and operating costs, no changes in working capital and includes the impact of realized risk management contracts.
(2) Funds flow from operations is a non-GAAP measure. Funds flow from operations does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales

	Q1 2017	Q4 2016	Q1 2016
Daily production/sales volumes			
Oil (bbls/d)	**10,105**	9,853	8,442
Bitumen – Blackrod (bbls/d) (2)	**542**	523	584
Combined (bbls/d)	**10,647**	10,376	9,026
Natural gas (Mcf/d)	**638**	620	845
Total production (boe/d) (1)	**10,753**	10,479	9,166
Product pricing (excluding risk management activities) (2)			
Oil ($/bbl)	**40.75**	38.83	16.77
Natural gas ($/Mcf)	**2.50**	2.90	1.77
Combined ($/boe) (1)	**40.48**	38.61	16.67
Sales ($000s) (2)			
Oil and gas sales – gross	**37,204**	35,360	13,021
Royalties	**(5,422)**	(4,516)	(1,345)
Oil and gas revenues – net (3)	**31,782**	30,844	11,676

(1) Natural gas production converted at 6:1 (for boe figures).
(2) All sales and expenses from the Blackrod SAGD pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established.
(3) Excludes deferred consideration amount recognized during the period.

Oil and natural gas sales increased 186% in the first quarter of 2017 to $37.2 million from $13.0 million in the same period in 2016. The increase in oil and gas sales is attributable to a 143% increase in average sale price received and a 17% increase in production volumes (on a boe basis) in the first quarter of 2017 compared to the same period in 2016.

Higher WTI crude oil prices partially offset by slightly wider heavy oil differentials contributed to an increase in our realized crude oil sales prices in the first quarter of 2017. Our average oil wellhead sales price in the first quarter of 2017, prior to the impact of risk management activities, was $40.75 per bbl compared with $16.77 per bbl in the same period in 2016.

Production growth in the first quarter of 2017 compared to the same period in 2016 is mainly attributable to the first phase of the Onion Lake thermal project. During the first quarter of 2017, production from this project averaged 6,182 bbls/d, with a steam to oil ratio of 2.52 compared with 4,252 bbls/d during the same period in 2016.

Production in our non-thermal areas increased in the first quarter of 2017 compared to the fourth quarter of 2016. With the improvement in crude oil prices we selectively brought back on production certain shut-in wells at Onion Lake and re-initiated a portion of the ASP flood at Mooney. Production from the re-initiated ASP flood at Mooney is expected to ramp-up over the course of 2017. We still have approximately 500 bbls of oil per day currently shut-in at Onion Lake. We expect oil prices would have to improve to US$55 to US$60 per bbl before we would consider putting some of these shut-in wells back on production.

On a boe basis, 99% of the Company's oil and natural gas production in the first quarter of 2017 was heavy oil or bitumen. The Onion Lake area accounted for 77% of total production in the first quarter of 2017.

Production by area (boe/d)	**Q1 2017**	Q4 2016	Q1 2016
Onion Lake - thermal	**6,182**	6,119	4,252
Onion Lake - conventional	**2,147**	2,011	2,232
Mooney	**942**	785	1,042
John Lake	**808**	837	861
Blackrod	**542**	523	584
Other	**132**	204	195
Total production	**10,753**	10,479	9,166

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. A second pilot well pair was drilled and put on production in 2013. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. The original SAGD pilot well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. During the first quarter of 2017, the pilot well produced an average of 542 bbls/d of bitumen and generated net revenues of $0.4 million ($0.7 million loss in the first quarter of 2016).

During 2016, BlackPearl received regulatory approval for its 80,000 bbls/d commercial Blackrod SAGD project. The commercial Blackrod SAGD project has not yet been sanctioned for development by our Board of Directors. We will consider joint venture opportunities or other financing options to accelerate development of the Blackrod SAGD project.

Risk Management Activities

The Company periodically enters into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy is to mainly focus on swaps, collars, calls and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes. The policy permits the Company to hedge up to 60% of our forecast production for a period of up to 24 months.

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the fair values of our outstanding risk management contracts. The Company had a net gain of $5.9 million on its risk management contracts during the first quarter of 2017, consisting of a $0.3 million realized gain on the contracts and an unrealized gain of $5.6 million. The realized gain on risk management contracts was the equivalent of adding $0.37 per bbl to our wellhead price during the first quarter of 2017.

($000s, except per boe)	**Q1 2017**	Q4 2016	Q1 2016
Realized gain on risk management contracts	**342**	578	6,120
Per boe ($)	**0.37**	0.63	7.84
Unrealized gain (loss) on risk management contracts	**5,569**	(5,676)	(472)

The table below summarizes the Company's outstanding commodity contracts as at March 31, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap
Oil	500 bbls/d	April 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar
Oil	1,000 bbls/d	April 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
2018					
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call

At March 31, 2017, these contracts had a fair value of $0.4 million liability. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $5.6 million increase in fair value. A 10% increase to the oil price used to calculate the fair value of these contracts would result in an approximate $8.1 million decrease in fair value.

The table below summarizes commodity contracts the Company entered into subsequent to March 31, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap

Royalties

	Q1 2017	Q4 2016	Q1 2016
Royalties ($000s)	**5,422**	4,516	1,345
Per boe ($)	**5.90**	4.93	1.72
As a percentage of oil and gas sales	**15%**	13%	10%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, the majority of the royalties are paid to Indian Oil and Gas Canada on behalf of the Onion Lake Cree Nation.

Royalties were $5.4 million in the first quarter of 2017, an increase from $1.3 million in the same period in 2016. The increase in royalties is primarily attributable to higher revenues in 2017. Royalties as a percentage of oil and gas sales increased to 15% in the first quarter of 2017 from 10% in the same period in 2016. Royalty rates are generally price sensitive and the higher oil prices realized in the first quarter of 2017 resulted in higher royalties as a percentage of oil and gas sales. In addition, the Company sold a royalty interest in December 2016 on substantially all production from its Onion Lake lands and, as a result, at Onion Lake the Company paid an additional royalty of approximately 1.75% in the first quarter of 2017.

Transportation Costs

	Q1 2017	Q4 2016	Q1 2016
Conventional Production			
Transportation costs ($000s)	**407**	318	318
Per boe ($)	**1.12**	0.93	0.81
Thermal Production			
Transportation costs ($000s)	**2,043**	2,144	1,775
Per boe ($)	**3.67**	3.81	4.59
Total Production			
Transportation costs ($000s)	**2,450**	2,462	2,093
Per boe ($)	**2.67**	2.69	2.68

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Costs to ship oil/emulsion to a treating facility before it is sold are included in production expenses rather than transportation costs. Transportation costs increased in the first quarter of 2017 to $2.5 million from $2.1 million in the same period of 2016. The increase in transportation costs is primarily attributable to increased production from the first phase of the Onion Lake thermal project which ships mostly clean marketable crude oil.

Production Costs

	Q1 2017	Q4 2016	Q1 2016
Conventional Production			
Production costs ($000s)	**8,858**	6,387	5,550
Per boe ($)	**24.43**	18.59	14.09
Thermal Production			
Production costs ($000s)	**4,925**	4,701	4,093
Per boe ($)	**8.85**	8.35	10.58
Total Production			
Production costs ($000s)	**13,783**	11,088	9,643
Per boe ($)	**15.00**	12.11	12.35

Total production costs increased 43% in the first quarter of 2017 to $13.8 million from $9.6 million in the same period in 2016. On a per boe basis, total production costs increased 21% in the first quarter of 2017 to $15.00 per boe from $12.35 per boe in the same period in 2016.

The increase in total production costs during the first quarter of 2017 was primarily attributable to an increase in our conventional production costs. The re-initialization of a portion of the ASP flood at Mooney resulted in an increase in chemical and injection costs during the quarter. In addition, we incurred workover costs on the wells we restarted at Mooney and Onion Lake. Conventional production costs are expected to decrease during the remainder of the year as our workover activities return to normal levels.

The increase in thermal production costs in the first quarter of 2017 compared to the same period in 2016 is primarily attributable to increased production volumes and higher gas consumption costs as a result of higher natural gas prices in 2017. On a boe basis however, thermal production costs decreased due to a 45% increase in production volumes during the first quarter of 2017 compared to the same period in 2016. Thermal production costs were fairly consistent between the first quarter of 2017 and the fourth quarter of 2016 with a slight increase in 2017 as the result of higher maintenance costs.

Operating Netback [1] [2]

	Q1 2017		Q4 2016		Q1 2016	
	$000s	**$/boe**	$000s	$/boe	$000s	$/boe
Oil and gas sales	**37,204**	**40.48**	35,360	38.61	13,021	16.67
Royalties	**5,422**	**5.90**	4,516	4.93	1,345	1.72
Transportation costs	**2,450**	**2.67**	2,462	2.69	2,093	2.68
Production costs	**13,783**	**15.00**	11,088	12.11	9,643	12.35
Operating netback before realized risk management contracts	**15,549**	**16.91**	17,294	18.88	(60)	(0.08)
Realized gain on risk management contracts	**342**	**0.37**	578	0.63	6,120	7.84
Operating netback after realized risk management contracts	**15,891**	**17.28**	17,872	19.51	6,060	7.76

(1) Operating netback is a non-GAAP measure. Operating netback does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

(2) Production used when calculating operating netback is determined by the number of days in the period multiplied by average daily production less capitalized production at Blackrod as disclosed in the Oil and Gas, Oil and Gas Pricing and Oil and Gas Sales section of this MD&A. (Q1 2017 – 10,211 boe/d; Q4 2016 – 9,956 boe/d; Q1 2016 – 8,582 boe/d)

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, before realized gains on risk management activities, increased in the first quarter of 2017 to $16.91 per boe from a loss of $0.08 per boe in the same period in 2016. The increase is primarily attributable to the increase in realized crude oil prices, partially offset by higher royalties and production costs.

General and Administrative Expenses (G&A)

($000s, except per boe)	**Q1 2017**	Q4 2016	Q1 2016
Gross G&A expense	**3,023**	1,774	2,129
Operator recoveries	**(236)**	(191)	(230)
Net G&A expense	**2,787**	1,583	1,899
Per boe ($)	**3.03**	1.73	2.43

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The increase in gross G&A expenses in the first quarter of 2017 compared to the same period in 2016 reflects higher staff compensation costs in 2017. As oil prices stabilized during the first quarter of 2017, previous salary reductions were rescinded and performance incentive payments to staff were made.

Stock-Based Compensation

($000s, except per boe)	**Q1 2017**	Q4 2016	Q1 2016
Gross stock-based compensation	**570**	700	1,178
Recoveries from forfeitures	**(5)**	(6)	(48)
Net stock-based compensation	**565**	694	1,130
Per boe ($)	**0.62**	0.76	1.45

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options and restricted share units (RSUs) granted. The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants whereby the fair value of all stock options granted is recorded as a charge to operations over the period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. The Company accounts for RSUs as equity based awards and the estimated fair value of the awards is determined at the time of grant.

On February 27, 2017, the Company's Board of Directors approved, subject to shareholder approval, the adoption of an RSU plan. Under the terms of the RSU plan, the directors can issue up to 5,000,000 common shares from treasury to holders of RSUs.

RSUs are notional share instruments which track the value of the common shares. RSUs granted to officers and directors cliff vest three years from the date of grant. RSUs granted to all other eligible plan participants vest over three years; one third on the first, second and third anniversary from the date of the grant. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Company's Board of Directors. During the first quarter of 2017, 1,760,000 RSUs were granted to officers, directors and other eligible plan participants.

The decrease in gross stock-based compensation in the first quarter of 2017 compared to the same period in 2016 is primarily attributable to a decrease in the weighted average options outstanding during 2017. In the first quarter of 2017, 246,673 options were exercised, 1,642,000 options were granted and 53,333 options were forfeited. Based on stock options and RSUs outstanding as at March 31, 2017, the Company has an unamortized stock based compensation expense of approximately $4.3 million, of which $1.7 million is expected to be expensed in the remainder of 2017, $1.4 million in 2018, $1.0 million in 2019 and $0.2 million in 2020.

Finance Costs

($000s)	**Q1 2017**	Q4 2016	Q1 2016
Interest & financing charges	**162**	523	835
Accretion of decommissioning liabilities	**387**	377	366
Total finance costs	**549**	900	1,201

The decrease in interest and financing charges in the first quarter of 2017 compared to the same period in 2016 is the result of the Company having no advances on its credit facilities during the three months ended March 31, 2017. The majority of interest and financing charges in the first quarter of 2017 relates to standby fees on the unused credit facilities. Our credit facilities are floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on our credit facilities is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). We have not entered into any financial instruments to fix the interest rate on our debt.

Depletion and Depreciation

	Q1 2017	Q4 2016	Q1 2016
Depletion and depreciation ($000s)	**10,953**	11,237	10,632
Per boe ($)	**11.92**	12.27	13.61

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense increased in the first quarter of 2017 to $11.0 million from $10.6 million in the same period in 2016. On a boe basis, depletion and depreciation expense decreased to $11.92 per boe in the first quarter of 2017 compared to $13.61 per boe in the same period in 2016. The decrease in depletion and depreciation on a boe basis is primarily attributable to a higher proportion of our production generated from the Onion Lake thermal project in the first quarter of 2017. The depletion rate on this project is below $10 per boe which is lower than the depletion rates for our other producing areas.

There were no impairment losses or reversals recorded for the three months ended March 31, 2017. However, declines in forecast commodity prices could reduce reserve values and result in the recognition of future asset impairments. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Gain on Disposition of Properties

During the first quarter of 2017, the Company completed dispositions of non-producing properties for proceeds totaling $3.4 million resulting in a gain of $1.1 million during the period.

Income Taxes

BlackPearl did not pay cash income taxes in the first three months of 2017 and does not expect to pay income taxes during the remainder of 2017 as we have sufficient tax pools to shelter expected income.

RESULTS FROM OPERATIONS

	Q1 2017	Q4 2016	Q1 2016
Net income (loss) ($000s)	**7,814**	(2,217)	(9,322)
Per share, basic ($)	**0.02**	(0.01)	(0.03)
Per share, diluted ($)	**0.02**	(0.01)	(0.03)

For the quarter ended March 31, 2017, the Company recognized net income of $7.8 million compared to a net loss of $9.3 million in the same period in 2016. The increase in net income in 2017 is primarily a result of increased revenue from higher realized wellhead prices partially offset by higher royalties and production costs.

($000s)	**Q1 2017**	Q4 2016	Q1 2016
Cash flow from operating activities (1)	**14,786**	15,079	3,787
Funds flow from operations (2)	**12,924**	15,798	3,278

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Funds flow from operations is a non-GAAP measure. Funds flow from operations does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Funds flow from operations increased 294% to $12.9 million during the first quarter of 2017 compared to $3.3 million in the same period in 2016. The increase in funds flow in 2017 is primarily a result of higher realized wellhead prices partially offset by higher royalties and production costs.

Cash flow from operating activities differs from funds flow from operations principally due to the inclusion of decommissioning costs incurred and changes in non-cash working capital. For the three months ended March 31, 2017, cash flow from operating activities was higher than funds flow from operations due to changes in non-cash working capital of $1.9 million.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**March 31, 2017**	December 31, 2016
Working capital deficiency (surplus)	**(3,576)**	4,995
Long-term debt	**-**	-
Net debt (surplus) (1)	**(3,576)**	4,995

(1) Net debt (surplus) is a non-GAAP measure. Net debt does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

At March 31, 2017, the Company had working capital of $3.6 million, no amounts drawn on its $117.5 million credit facilities and had issued letters of credit in the amount of $20,000; leaving $117.5 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by May 31, 2017. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet (excluding any current amounts due on credit facilities). In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 6.9 at March 31, 2017 and was in compliance with this covenant at March 31, 2017.

($000s, except working capital ratio)	**March 31, 2017**	December 31, 2016
Current assets per consolidated financial statements	**24,348**	19,510
Add: amount available to be drawn on credit facilities	**117,500**	117,500
Current assets for working capital ratio	**141,848**	137,010
Current liabilities per consolidated financial statements	**20,772**	24,505
Less: current risk management liabilities	**(233)**	(5,507)
Current liabilities for working capital ratio	**20,539**	18,998
Working capital ratio	**6.9**	7.2

During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project with total estimated capital costs between $180 and $185 million. The Company has entered into a fixed price agreement to fabricate the central processing facilities and pad facilities for this second phase. Expected cash flow from operating activities and the Company's borrowing capacity on our existing credit facilities is expected to be used to fund a significant portion of the capital costs of the second phase of the Onion Lake thermal project. In addition, we are exploring additional debt financing options to fund the development of the second phase of the Onion Lake thermal project. The project is expected to be completed in mid-2018.

The Company has received regulatory approval for its 80,000 bbls/d commercial Blackrod SAGD project and is planning to build this project in phases, with the first phase likely to be designed for 20,000 bbls/d. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. We currently would consider financing options to accelerate the development of this project, including joint venture opportunities.

At March 31, 2017, there were 336,195,568 common shares issued and outstanding. In the first quarter of 2017 the Company issued 246,673 common shares for net proceeds of $0.2 million pursuant to the exercise of stock options.

The Company did not pay dividends on its common shares in the first quarter of 2017 and it does not anticipate paying dividends in the near term. Dividends are at the discretion of the Company's Board of Directors. In addition, the terms and conditions of the Company's existing credit agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending during the first quarter of 2017 was $13.4 million, an increase from $2.1 million during the same period in 2016. The main components of the capital spending during the first quarter were construction costs for the second phase of the Onion Lake thermal project, drilling of two horizontal heavy oil wells at John Lake and costs to bring shut-in production back online at Mooney. The Company also completed dispositions of non-producing properties for proceeds totaling $3.4 million during the first quarter.

($000s)	**Q1 2017**	Q4 2016	Q1 2016
Land	**1,865**	428	117
Seismic	**-**	9	(5)
Drilling and completion	**3,781**	560	1,464
Equipment and facilities	**7,707**	5,079	494
Other	**3**	74	7
Total	**13,356**	6,150	2,077
Property acquisitions	**-**	-	-
Total capital expenditures	**13,356**	6,150	2,077
Proceeds on disposition	**(3,421)**	(55,000)	-
Net capital expenditures	**9,935**	(48,850)	2,077

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the contractual obligations and commitments of the Company outstanding as at March 31, 2017. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

($000s)	2017	2018	2019	2020	2021	Thereafter
Operating leases (1)	730	902	694	556	545	-
Electrical service agreement (2)	708	585	119	119	119	1,868
Transportation service agreement (3)	101	135	135	33	-	-
Decommissioning liabilities (4)	602	428	347	8,992	1,651	62,706
Capital commitments (5)	65,190	5,000	5,000	-	-	-
	67,331	7,050	6,295	9,700	2,315	64,574

(1) The Company's most significant operating lease is for office space.

(2) The Company entered into certain long-term agreements to acquire electricity for one of its processing facilities.

(3) The Company entered into certain long-term agreements to transport natural gas to one of its facilities.

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $74.7 million as at March 31, 2017. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) The Company entered into certain agreements pertaining to the construction of the second phase of the Onion Lake thermal project.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair values of the Company's risk management contracts are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

See the Company's unaudited consolidated financial statements for the three months ended March 31, 2017 for details on the risks associated with these financial instruments including credit risk, liquidity risk, interest rate risk, foreign currency exchange risk and commodity price risk.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended March 31, 2017 or 2016. We do utilize various operating leases in our normal course of business as disclosed under Contractual Obligations and Commitments.

RELATED-PARTY TRANSACTIONS

There was no significant related-party transactions during the period ended March 31, 2017 or 2016 except for key management compensation.

OUTSTANDING SHARE DATA, STOCK OPTIONS AND RESTRICTED SHARE UNITS

As at May 3, 2017, the Company had 336,208,902 common shares outstanding, 28,214,996 stock options outstanding and 1,710,000 restricted share units outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at May 3, 2017, the Company had not drawn any amounts under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $117,480,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of May 3, 2017, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the interim consolidated financial statements in accordance with IFRS requires that management use judgement and make estimates and assumptions regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Further information on the Company's critical accounting estimates can be found in the notes to the annual consolidated financial statements and annual MD&A for the year ended December 31, 2016. There have been no significant changes to the Company's critical accounting estimates as of March 31, 2017.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements are listed below.

In May 2014, the IASB issued IFRS 15, *"Revenue from Contracts with Customers"* ("IFRS 15") to replace IAS 11, *"Construction Contracts"*, IAS 18, *"Revenue"* and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2018 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

In July 2014, the IASB issued IFRS 9, *"Financial Instruments"* ("IFRS 9") which is intended to replace IAS 39, *"Financial Instruments: Recognition and Measurement."* IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases."* Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements.

RISK FACTORS

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2016 for a discussion of the risks and uncertainties associated with the Company's activities. There have been no significant changes in these risks and uncertainties during the first three months of 2017.

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting ("ICFR") in the annual MD&A for the year ended December 31, 2016. There have been no changes to ICFR in the three months ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the ICFR will prevent all errors or fraud.

OUTLOOK

2017 Guidance	Initial Guidance	Q1 Update
Production (boe/d)		
Annual average	10,000 – 11,000	10,000 – 11,000
Cash flow from operating activities (1) ($millions)	65 – 70	55 - 60
Funds flow from operations (2) ($millions)	65 – 70	55 - 60
Capital expenditures ($millions)	200	185 - 190
Year-end debt ($millions)	135 - 140	130 - 135
Pricing Assumptions (annual average)		
Crude oil - WTI	US $54.50	US $52.75
Light/heavy differential	US $14.75	US $13.55
Foreign Exchange (Cdn$ to US$)	0.75	0.75

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.

(2) Funds flow from operations is a non-GAAP measure. Funds flow from operations does not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies in the oil and gas industry.

Our plan for the remainder of 2017 is relatively unchanged with the focus being the expansion of the Onion Lake thermal project with a target completion date of mid-2018. We are planning to spend between $185 and $190 million on capital projects, down from our initial guidance of $200 million. The decrease in capital spend is the result of deferring drilling on some our conventional heavy oil projects at John Lake, Onion Lake and other minor project areas to future periods, as well as adjusting the timing of expenditures on the Onion Lake thermal expansion.

The capital program is expected to be funded from a combination of our anticipated funds flow from operations and our undrawn credit facilities. Funds flow from operations is expected to be between $55 and $60 million, down from our initial guidance of $65 to $70 million. The decrease in funds flow from operations reflects a change in the average wellhead price we expect to receive from the remainder of the year. Year-end 2017 debt levels are anticipated to be between $130 and $135 million, down from our initial guidance of $135 and $140 million. The decrease in year-end debt levels reflects a decrease in capital spending for the remainder of the year. We are looking to supplement these sources with $75 to $100 million of additional term debt financing to provide us with financial flexibility during the construction phase. In the event that we are unable to obtain additional financing we will reduce capital spending on our conventional heavy oil projects.

We anticipate oil and gas production to average between 10,000 and 11,000 boe/d in 2017, unchanged from our initial guidance. This includes reactivating a portion of the ASP flood at Mooney which is expected to ramp-up over the course of 2017.

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as “anticipate”, “anticipated”, “approximately”, “plan”, “planning”, “planned”, “could”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expected”, “may”, “impact”, “new”, “will”, “scheduled”, “outlook” or similar words suggesting future outcomes.

In particular, but without limiting the foregoing, this report contains forward-looking statements pertaining to our business plans and strategies; capital expenditure and drilling programs including:

- Total estimated capital costs for the second phase of the Onion Lake thermal project as discussed in the 2017 Significant Events section;
- Percentage of total estimated capital costs for the second phase of the Onion Lake thermal project included in the fixed price agreement to fabricate the central processing facilities and pad facilities as discussed in the 2017 Significant Event section;
- The estimated change in annualized funds flow from operations for 2017 due to changes in key variables as discussed in the Commodity Prices section;
- The expected oil price we would need before we selectively brought back on shut-in wells at Onion Lake as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Exploring financing options and estimated costs to accelerate development of the Blackrod SAGD project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section and the Liquidity and Capital Resources section;
- Expected stock-based compensation expense for the remainder of 2017, 2018, 2019 and 2020 as discussed in the Stock-based Compensation section;
- Potential future asset impairments or reversals of impairments as discussed in the Impairment section;
- Expected cash taxes to be paid during the remainder of 2017 as discussed in the Income Taxes section;
- Exploring financing options and estimated costs to expand our Onion Lake thermal project as discussed in the Liquidity and Capital Resources section;
- The Company’s expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

The forward-looking statements in this document reflect certain assumptions and expectations by management. The key assumptions that have been made in connection with these forward-looking statements include the continuation of current or, where applicable, assumed industry conditions, the continuation of existing tax, royalty and regulatory regimes, commodity price and cost assumptions, the continued availability of cash flow or financing on acceptable terms to fund the Company’s capital programs, the accuracy of the estimate of the Company’s reserves and resource volumes and that BlackPearl will conduct its operations in a manner consistent with past operations. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties which could cause actual results to differ materially from those contained in forward-looking statements. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent; risks related to the exploration, development and production of crude oil, natural gas and NGLs reserves; general economic, market and business conditions; substantial capital requirements; uncertainties inherent in estimating quantities of reserves and resources; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; the need to obtain regulatory approvals on projects before development commences; environmental risks and hazards and the cost of compliance with environmental regulations; aboriginal claims; inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions; potential cost overruns; variations in foreign exchange rates; diluent supply shortages; competition for capital, equipment, new leases, pipeline capacity and skilled personnel; uncertainties inherent in the SAGD bitumen and ASP recovery processes; credit risks associated with counterparties; the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, leases and permits; reliance on third parties for pipelines and other infrastructure; changes in royalty regimes; failure to accurately estimate abandonment and reclamation costs; inaccurate estimates and assumptions by management; effectiveness of internal controls; the potential lack of available drilling equipment and other restrictions; failure to obtain or keep key personnel; title deficiencies with the Company’s assets; geo-political risks; risks that the Company does not have adequate insurance coverage; risk of litigation and risks arising from future acquisition activities. Further information regarding these risk factors and others may be found under "Risk Factors" in the Annual Information Form.

Undue reliance should not be placed on these forward-looking statements. Readers are cautioned that the actual results achieved will vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive. Consequently, there is no assurance by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this document are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Other Supplementary Information

1. **List of directors and officers at May 3, 2017**
   a. **Directors:**
      John Craig
      John Festival
      Brian Edgar
      Keith Hill
      Vic Luhowy

   b. **Officers:**
      John Craig, Chairman
      John Festival, President and Chief Executive Officer
      Don Cook, Chief Financial Officer and Corporate Secretary
      Chris Hogue, Vice President Operations
      Ed Sobel, Vice President Exploration

2. **Financial Information**
   The report for the year ended December 31, 2017 is expected to be published on or before February 28, 2018.

3. **Other Information**
   Address (Corporate head office):
   BlackPearl Resources Inc.
   900, 215 – 9th Avenue S.W.
   Calgary, Alberta T2P 1K3
   Canada
   Telephone: +1.403.215.8313
   Fax: +1.403.265.5359
   Website: www.blackpearlresources.ca

   The Canadian federal corporation number for the Company is 454611-3.

   For further information, please contact:
   John Festival - President and Chief Executive Officer, +1.403.215.8313
   Don Cook – Chief Financial Officer, +1.403.215.8313

BLACKPEARL RESOURCES INC.

Consolidated Balance Sheets

(unaudited) (Cdn$ in thousands)	Note		**March 31, 2017**		December 31, 2016
Assets					
Current assets					
Cash and cash equivalents	4	**$**	**9,603**	$	5,368
Trade and other receivables	5		**13,892**		13,391
Inventory			**151**		46
Prepaid expenses and deposits			**702**		705
			24,348		19,510
Exploration and evaluation assets	6		**171,570**		170,737
Property, plant and equipment	7		**541,817**		542,157
		$	**737,735**	$	732,404
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	8	**$**	**19,609**	$	17,950
Current portion of decommissioning liabilities	9		**559**		644
Current portion of deferred consideration	10		**371**		404
Fair value of risk management liabilities	14		**233**		5,507
			20,772		24,505
Fair value of risk management liabilities	14		**157**		452
Decommissioning liabilities	9		**71,953**		71,122
Deferred consideration	10		**14,359**		14,425
			107,241		110,504
Shareholders' equity					
Share capital	12		**970,814**		970,513
Contributed surplus			**43,473**		42,994
Deficit			**(383,793)**		(391,607)
			630,494		621,900
		$	**737,735**	$	732,404

Commitments and contingencies (note 13)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Income

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Revenue			
Oil and gas sales		**$ 37,204**	$ 13,021
Deferred consideration	10	**99**	-
Royalties		**(5,422)**	(1,345)
Net oil and gas revenue		**31,881**	11,676
Gain on risk management contracts	14	**5,911**	5,648
		37,792	17,324
Expenses			
Production		**13,783**	9,643
Transportation		**2,450**	2,093
General and administrative		**2,787**	1,899
Depletion and depreciation	7	**10,953**	10,632
Finance costs	15	**549**	1,201
Stock-based compensation	12	**565**	1,130
Foreign currency exchange loss		**10**	48
		31,097	26,646
Other income			
Gain on disposition of properties		**1,110**	-
Interest income		**9**	-
		1,119	-
Net and comprehensive income (loss) for the period		**$ 7,814**	$ (9,322)
Income (loss) per share			
Basic	12	**$ 0.02**	$ (0.03)
Diluted	12	**$ 0.02**	$ (0.03)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Three months ended March 31, 2017			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2017	$ 970,513	$ 42,994	$ (391,607)	$ 621,900
Net and comprehensive income for the period	-	-	7,814	7,814
Stock-based compensation	-	565	-	565
Shares issued on exercise of stock options	215	-	-	215
Transfer to share capital on exercise of stock options	86	(86)	-	-
Balance - March 31, 2017	**$ 970,814**	**$ 43,473**	**$ (383,793)**	**$ 630,494**

	Three months ended March 31, 2016			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2016	$ 970,134	$ 39,800	$ (371,679)	$ 638,255
Net and comprehensive loss for the period	-	-	(9,322)	(9,322)
Stock-based compensation	-	1,130	-	1,130
Balance - March 31, 2016	$ 970,134	$ 40,930	$ (381,001)	$ 630,063

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) (Cdn$ in thousands)	Note	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Operating activities			
Net and comprehensive income (loss) for the period		**$ 7,814**	$ (9,322)
Items not involving cash:			
Depletion and depreciation	7	**10,953**	10,632
Accretion of decommissioning liabilities	15	**387**	366
Stock-based compensation	12	**565**	1,130
Foreign exchange gain		**(17)**	-
Deferred consideration		**(99)**	-
Unrealized loss (gain) on risk management contracts	14	**(5,569)**	472
Gain on disposition of properties		**(1,110)**	-
Decommissioning costs incurred	9	**(42)**	(147)
Changes in non-cash working capital	15	**1,904**	656
Cash flow from operating activities		**14,786**	3,787
Financing activities			
Proceeds on issue of common shares, net of costs	12	**215**	-
Repayment of long-term debt		**-**	(2,000)
Cash flow from (used) in financing activities		**215**	(2,000)
Investing activities			
Capital expenditures - exploration and evaluation assets	6	**(767)**	(792)
Capital expenditures - property, plant and equipment	7	**(12,589)**	(1,285)
Proceeds from disposition of properties		**3,421**	-
Changes in non-cash working capital	15	**(859)**	(926)
Cash flow used in investing activities		**(10,794)**	(3,003)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**28**	48
Increase (decrease) in cash and cash equivalents		**4,235**	(1,168)
Cash and cash equivalents, beginning of period		**5,368**	2,300
Cash and cash equivalents, end of period		**$ 9,603**	$ 1,132

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.
Notes to the Consolidated Financial Statements
(tabular amounts in thousands of Cdn$, except as noted)
(unaudited)

1. GENERAL INFORMATION

BlackPearl Resources Inc. (together with its subsidiaries collectively referred to as the "Company" or "BlackPearl") is engaged in the business of oil and gas exploration, development and production in North America. The Company's primary focus is on heavy oil and oil sands projects in Western Canada. The Company's common shares are listed and traded on the TSX Exchange under the trading symbol "PXX". The Company's Swedish Depository Receipts trade on the NASDAQ Stockholm Exchange under the symbol "PXXS". BlackPearl is incorporated under the Canada Business Corporations Act and is located in Canada. The address of its registered office is 900, 215 – 9th Avenue SW, Calgary, Alberta, T2P 1K3.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three months ended March 31, 2017 have been prepared in accordance with IAS 34, Interim Financial Reporting under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and have been prepared following the same accounting policies and method of computation as the annual consolidated financial statements for the year ended December 31, 2016 except accounting policies noted below. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss.

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued, outstanding and effective as of May 3, 2017, the date they were approved and authorized for issuance by the Company's Board of Directors ("the Board"). Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ended December 31, 2017 could result in restatement of these interim consolidated financial statements.

The disclosures provided below are incremental to those included with the annual consolidated financial statements. Certain information and disclosures normally included in the notes to the annual consolidated financial statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim consolidated financial statements should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2016 which have been prepared in accordance with IFRS as issued by the IASB.

3. SIGNIFICANT ACCOUNTING POLICIES

Restricted Share Units ("RSUs")
Periodically, the Company will grant RSUs in exchange for the provision of services from certain employees, directors and officers. RSUs are accounted for as equity based awards and the estimated fair value of the awards is determined at the time of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The fair value is recognized over the vesting period as stock-based compensation expense, with a corresponding increase to contributed surplus. RSUs granted to officers and directors cliff vest three years from the date of grant. RSUs granted to all other eligible plan participants vest over three years; one third on the first, second and third anniversary from the date of the grant.

Accounting standards issued but not yet applied
The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements are listed below.

In May 2014, the IASB issued IFRS 15, *"Revenue from Contracts with Customers"* ("IFRS 15") to replace IAS 11, *"Construction Contracts"*, IAS 18, *"Revenue"* and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2018 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

In July 2014, the IASB issued IFRS 9, *"Financial Instruments"* ("IFRS 9") which is intended to replace IAS 39, *"Financial Instruments: Recognition and Measurement."* IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Company's consolidated financial statements.

In January 2016, the IASB issued IFRS 16, *"Leases"* ("IFRS 16") to replace IAS 17, *"Leases."* Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. IFRS 16 is effective for years beginning on or after January 1, 2019 with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements.

4. CASH AND CASH EQUIVALENTS

		March 31, 2017		December 31, 2016
Cash at financial institutions	**$**	**9,603**	$	5,368

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of March 31, 2017, US $2.2 million (December 31, 2016 – US $0.4 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

5. TRADE AND OTHER RECEIVABLES

		March 31, 2017		December 31, 2016
Trade accounts receivable	**$**	**13,363**	$	13,206
Receivables from joint operation partners		**340**		328
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**13,418**		13,249
Receivable from risk management contracts		**373**		48
Other receivables		**101**		94
Total trade and other receivables	**$**	**13,892**	$	13,391

Aging of trade and other receivables are as follows:

At March 31, 2017	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 13,363	$ -	$ -	$ -	$ 13,363
Receivables from joint operation partners	14	9	-	317	340
Allowance for doubtful accounts	-	-	-	(285)	(285)
Receivable from risk management contracts	373	-	-	-	373
Other receivables	7	-	-	94	101
Total trade and other receivables	$ 13,757	$ 9	$ -	$ 126	$ 13,892

At December 31, 2016	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 13,206	$ -	$ -	$ -	$ 13,206
Receivables from joint operation partners	2	6	1	319	328
Allowance for doubtful accounts	-	-	-	(285)	(285)
Receivable from risk management contracts	48	-	-	-	48
Other receivables	-	-	-	94	94
Total trade and other receivables	$ 13,256	$ 6	$ 1	$ 128	$ 13,391

6. EXPLORATION AND EVALUATION ASSETS

At January 1, 2016	$ 169,493
Expenditures	967
Change in decommissioning provision	277
At December 31, 2016	170,737
Expenditures	767
Change in decommissioning provision	66
At March 31, 2017	$ 171,570

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD pilot project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During the first three months of 2017, no assets were considered to be impaired.

The transfer of exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. The Company has received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date.

During the three months ended March 31, 2017, the Company capitalized net operating revenues totalling a gain of $0.4 million ($0.7 million loss during the three months ended March 31, 2016) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the three months ended March 31, 2017 (2016 - $Nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2016	$ 1,240,645	$ 3,507	$ 1,244,152
Expenditures	9,825	133	9,958
Change in decommissioning provision	3,681	-	3,681
Dispositions	(40,170)	-	(40,170)
At December 31, 2016	1,213,981	3,640	1,217,621
Expenditures	12,586	3	12,589
Change in decommissioning provision	335	-	335
Dispositions	(2,311)	-	(2,311)
At March 31, 2017	$ 1,224,591	$ 3,643	$ 1,228,234
Accumulated depletion and depreciation			
At January 1, 2016	$ 628,355	$ 2,483	$ 630,838
Depletion and depreciation	44,476	150	44,626
At December 31, 2016	672,831	2,633	675,464
Depletion and depreciation	10,916	37	10,953
At March 31, 2017	$ 683,747	$ 2,670	$ 686,417
Net book value			
December 31, 2016	$ 541,150	$ 1,007	$ 542,157
March 31, 2017	$ 540,844	$ 973	$ 541,817

During the three months ended March 31, 2017, the Company did not capitalize any borrowing costs related to development activities (2016 - $Nil). The Company did not capitalize any general and administrative costs related to development activities during the three months ended March 31, 2017 (2016 - $Nil).

At March 31, 2017, the Company performed a review of each of our CGUs for any indicators of impairment. The Company has five CGU's, one for each of our core areas of Onion Lake, Mooney and Blackrod and two CGU's for some of our minor properties. The Company determined that none of our CGUs had any indicators of impairment at March 31, 2017 and no impairment losses or reversals of property, plant and equipment were recorded during the three months ended March 31, 2017 (2016 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		March 31, 2017		December 31, 2016
Trade payables and accrued liabilities	**$**	**18,640**	$	16,879
Payables to joint operation partners		**279**		275
Other payables		**690**		796
Total accounts payable and accrued liabilities	**$**	**19,609**	$	17,950

Trade payables are non-interest bearing and are normally settled on a 30 to 60 day term.

9. DECOMMISSIONING LIABILITIES

The Company's decommissioning liability is an estimate of the reclamation and abandonment costs arising from the Company's ownership interest in oil and gas assets, including well sites, gathering systems, batteries, processing and thermal facilities. The total undiscounted amount of the estimated cash flows required to settle the Company's liabilities is approximately $74.7 million (December 31, 2016 - $74.3 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2.0% (December 31, 2016 – 2.0%) and discounted using a risk-free rate of 2.0% to 2.3% (December 31, 2016 – 2.0% to 2.3%) based on expected settlement date. Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement.

Changes to the decommissioning liability were as follows:

		Three months ended March 31, 2017		Year ended December 31, 2016
Decommissioning liability, beginning of the period	**$**	**71,766**	$	66,927
New liabilities recognized		**401**		103
Decommissioning costs incurred		**(42)**		(580)
Change in estimated costs of decommissioning		**-**		(2,813)
Change in inflation rate		**-**		6,864
Change in discount rate		**-**		(196)
Accretion expense		**387**		1,461
Decommissioning liability, end of the period		**72,512**		71,766
Less current portion of decommissioning liability		**(559)**		(644)
Non-current portion of decommissioning liability	**$**	**71,953**	$	71,122

10. DEFERRED CONSIDERATION

Deferred consideration was recorded on the sale of a royalty interest in 2016 that will be recognized over the oil and gas reserve life of the Company's Onion Lake property. Changes to deferred consideration were as follows:

		Three months ended March 31, 2017		Year ended December 31, 2016
Deferred consideration, beginning of the period	**$**	**14,829**	$	-
Sale of a royalty interest at Onion Lake		**-**		14,829
Recognition of deferred consideration		**(99)**		-
Deferred consideration, end of the period		**14,730**		14,829
Less current portion of deferred consideration		**(371)**		(404)
Non-current portion of deferred consideration	**$**	**14,359**	$	14,425

11. LONG-TERM DEBT

At March 31, 2017, the Company had credit facilities of $117.5 million, consisting of a $107.5 million syndicated revolving line of credit (December 31, 2016 - $107.5 million) and a non-syndicated operating line of credit of $10 million (December 31, 2016 - $10 million). At March 31, 2017, the Company had not drawn any amounts (December 31, 2016 – no amounts drawn) under these credit facilities and had letters of credit issued in the amount of $20,000 (December 31, 2016 - $20,000); leaving $117.5 million (December 31, 2016 - $117.5 million) available to be drawn under these facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by May 31, 2017. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

Pursuant to the terms of the credit agreement, advances may be made, at the Company's option, as direct advances, LIBOR advances, banker's acceptances or standby letters of credit/guarantees. These advances bear interest depending on the type of advancement at the lender's prime rate, banker's acceptance rate or LIBOR rates, plus applicable margins. The applicable margin charged by the lender is dependent upon the Company's debt to EBITDA ratio calculated at the Company's previous fiscal quarter end. The applicable margins range between 2.00% and 3.50%. The lending agreement defines debt as any advances outstanding on the credit facilities plus any outstanding letters of credit/guarantee. The lending agreement defines EBITDA as comprehensive income before income tax, financing charges, non-cash items deducted in determining comprehensive income, unrealized gains or losses on risk management contracts and any income/losses attributable to assets acquired or disposed of when determining net comprehensive income for the period as indicated on the Company's consolidated statement of comprehensive income. The Company also incurs a standby fee for undrawn amounts.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculation of current assets and current liabilities. The Company had a working capital ratio of 6.9:1 at March 31, 2017 (December 31, 2016 – 7.2:1) and, accordingly, was in compliance with this covenant at March 31, 2017.

12. SHARE CAPITAL

(a) Authorized

The Company is authorized to issue an unlimited number of common shares.

(b) Common Shares Issued

	Number of Shares	**Attributed Value**
Balance as at January 1, 2016	335,638,226	$ 970,134
Shares issued on exercise of stock options	310,669	271
Transferred from contributed surplus on exercise of stock options	-	108
Balance as at December 31, 2016	335,948,895	$ 970,513
Shares issued on exercise of stock options	246,673	215
Transferred from contributed surplus on exercise of stock options	-	86
Balance as at March 31, 2017	336,195,568	$ 970,814

(c) Restricted Share Units (“RSUs”) Outstanding

On February 27, 2017, the Board approved, subject to shareholder approval, the adoption of a RSU plan. Under the terms of the RSU plan, the directors can issue up to 5,000,000 common shares from treasury to holders of RSUs.

RSUs are notional share instruments which track the value of the common shares. RSUs granted to officers and directors cliff vest three years from the date of grant. RSUs granted to all other eligible plan participants vest over three years; one third on the first, second and third anniversary from the date of the grant. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board. During the first quarter of 2017, 1,000,000 RSUs were granted to officers and directors and 760,000 RSUs were granted to other eligible plan participants.

The Company accounts for RSUs as equity based awards and the estimated fair value of the awards is determined at the time of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. During the three months ended March 31, 2017, 1,760,000 RSUs were granted (2016 – Nil) and the fair value of these RSUs was estimated using a forfeiture rate of 10.2% and a weighted average fair value of $1.56 per unit.

(d) Stock Options Outstanding

The Company has a stock option plan (the “Plan”) available to directors, officers, employees and certain consultants of the Company. The number of common shares to be reserved and authorized for issuance pursuant to the Plan and all other security based compensation arrangements (such as the RSU plan) cannot exceed 10% of the total number of issued and outstanding shares in the Company. The term and the vesting period of any options granted are determined at the discretion of the Board. The maximum term for options granted is ten years; however, all of the options granted by the Company have a term of five years or less. The exercise price of the option cannot be less than the five-day volume weighted average trading price of the common shares immediately preceding the day the option is granted.

The following table summarizes stock options outstanding:

	Number of Options	Weighted Average Exercise Price ($)
Outstanding at January 1, 2016	29,655,169	2.04
Granted	135,000	0.93
Exercised	(310,669)	0.87
Forfeited	(478,665)	3.04
Expired	(2,074,500)	5.18
Outstanding at December 31, 2016	26,926,335	1.79
Granted	1,642,000	1.56
Exercised	(246,673)	0.87
Forfeited	(53,333)	2.08
Outstanding at March 31, 2017	28,268,329	1.79

Options outstanding and exercisable as at March 31, 2017 are summarized below:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices ($)	Number of Options Outstanding	Weighted-Average Exercise Price ($)	Weighted-Average Remaining Life (Years)	Number of Options Exercisable	Weighted-Average Exercise Price ($)	Weighted-Average Remaining Life (Years)
0.71 – 1.50	10,826,162	0.84	3.23	6,983,380	0.84	3.22
1.51 – 3.00	15,787,667	2.23	2.26	14,080,668	2.31	1.95
3.01 – 3.87	1,654,500	3.73	0.23	1,654,500	3.73	0.23
	28,268,329	1.79	2.51	22,718,548	1.96	2.22

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the three months ended March 31, 2017, 1,642,000 options were granted (2016 – 75,000). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	**Three months ended March 31, 2017**	Three months ended March 31, 2016
Risk free interest rate (%)	**1.0**	0.6
Dividend yield (%)	**0.0**	0.0
Expected life (years)	**3.8**	3.7
Expected volatility (%)	**56.4**	54.6
Forfeiture rate (%)	**10.2**	11.7
Weighted average fair value of options	**$ 0.67**	$ 0.32

(e) Stock-based Compensation

		Three months ended March 31, 2017		Three months ended March 31, 2016
Gross stock-based compensation related to options	**$**	**488**	$	1,178
Gross stock-based compensation related to RSUs		**82**		-
Total gross stock-based compensation		**570**		1,178
Recoveries from forfeitures related to options		**(5)**		(48)
Net stock-based compensation	**$**	**565**	$	1,130

(f) Income (loss) per Share

Basic income (loss) per share amounts are calculated by dividing net and comprehensive income (loss) for the period by the weighted average number of common shares outstanding during the period.

The following table shows the calculation of basic and diluted income (loss) per share:

		Three months ended March 31, 2017		Three months ended March 31, 2016
Net and comprehensive income (loss)	**$**	**7,814**	$	(9,322)
Weighted average number of common shares - basic		**336,157**		335,638
Dilutive effect:				
Outstanding options		**4,543**		-
Weighted average number of common shares - diluted		**340,700**		335,638
Basic income (loss) per share	**$**	**0.02**	$	(0.03)
Diluted income (loss) per share	**$**	**0.02**	$	(0.03)

For the three months ended March 31, 2017, the Company used a weighted average market closing price of $1.53 per share to calculate the dilutive effect of stock options. For the three months ended March 31, 2017, 16,395,223 options were antidilutive (2016 – all outstanding options were anti-dilutive) and were not included in the calculation of diluted income (loss) per share.

13. COMMITMENTS AND CONTINGENCIES

	2017	2018	2019	2020	2021	Thereafter
Operating leases [1]	$ 730	$ 902	$ 694	$ 556	$ 545	$ -
Electrical service agreement [2]	708	585	119	119	119	1,868
Transportation service agreement [3]	101	135	135	33	-	-
Decommissioning liabilities [4]	602	428	347	8,992	1,651	62,706
Capital commitments [5]	65,190	5,000	5,000	-	-	-
Total	$ 67,331	$ 7,050	$ 6,295	$ 9,700	$ 2,315	$ 64,574

(1) The Company's most significant operating lease is for office space.

(2) The Company entered into certain long-term agreements to acquire electricity for one of its processing facilities.

(3) The Company entered into certain long-term agreements to transport natural gas to one of its facilities.

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $74.7 million as at March 31, 2017. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) The Company entered into certain agreements pertaining to the construction of the second phase of the Onion Lake thermal project.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities.

(a) Fair value of financial instruments

The following table summarizes the carrying value and fair value of the Company's financial assets and liabilities.

	March 31, 2017		December 31, 2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial assets				
Loans and receivables:				
Cash and cash equivalents	**$ 9,603**	**$ 9,603**	$ 5,368	$ 5,368
Trade and other receivables	**$ 13,892**	**$ 13,892**	$ 13,391	$ 13,391
Deposits	**$ 224**	**$ 224**	$ 142	$ 142
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	**$ 19,609**	**$ 19,609**	$ 17,950	$ 17,950
Financial liabilities at fair value through profit or loss:				
Risk management liabilities	**$ 390**	**$ 390**	$ 5,959	$ 5,959

The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair values of the Company's risk management contracts use level 2 valuation methods and are determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

The fair values of financial instruments have been determined by various valuation methods as defined below:

- Level 1: fair value is based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value is based on inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3: fair value is based on inputs for the asset or liability that are not based on observable market data (unobservable inputs).

(b) Risks associated with financial instruments

The following summarizes the risks associated with the Company's financial instruments:

(i) Credit Risk

Credit risk is the risk that a third party fails to meet its contractual obligations that could result in the Company incurring a loss.

As at March 31, 2017, the Company held $9.6 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 72% of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited.

At March 31, 2017, 96% of receivables were from oil and gas marketers related to the sale of our oil and gas production. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate the credit risk associated with these marketers by assessing their financial strength and entering into relationships with larger purchasers with established credit history. During the first quarter of 2017, the Company did not experience any collection issues with its marketers.

In the first quarter of 2017, the Company had four customers which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these collective customers represented approximately 87% of the Company's total oil and gas sales in the first quarter of 2017.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During the first quarter of 2017, the Company did not experience any collection issues with risk management contracts.

The Company typically does not obtain or post collateral or security from its oil and natural gas marketers or financial institution counterparties. The carrying amounts of accounts receivable represent the maximum credit exposure. The Company is not the operator of certain oil and natural gas properties in which it has an ownership interest. The Company is dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the Company's activities may be impacted by the ability, expertise, judgment and financial capability of the operators.

(ii) Liquidity risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at March 31, 2017, the Company had $117.5 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that a financial instrument, or cash flows associated with the instrument, will fluctuate due to changes in market interest rates. The Company is exposed to interest rate risk related to interest expense on its credit facilities due to the floating interest rate charged on advances. During the three months ended March 31, 2017, the Company had no advances on its credit facilities and therefore changes in interest rates would not have had an effect on income during the period. The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

(iv) Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily priced in US dollars while most of the Company's operating and capital expenditures are denominated in Canadian dollars and (ii) certain deposits and accounts payable are denominated in US dollars. As at March 31, 2017, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at March 31, 2017, the Company held US $2.2 million in cash and cash equivalents and US $0.4 million in accounts payable and accrued liabilities. If exchange rates to convert from US dollars to Canadian dollars had been $0.10 lower with all other variables held constant, income for the three months ended March 31, 2017 would have been approximately $0.2 million lower as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at March 31, 2017. An equal opposite impact would have occurred to income had exchange rates been $0.10 higher.

(v) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 2% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current revenues.

From time to time, the Company enters into certain risk management contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These risk management contracts are not used for trading or speculative purposes. The Company has not designated its risk management contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all risk management contracts to be economic hedges. As a result, all risk management contracts are recorded at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the statement of comprehensive income.

Risk management amounts recognized were as follows:

		Three months ended March 31, 2017		Three months ended March 31, 2016
Realized gain on risk management contracts	**$**	**342**	$	6,120
Unrealized gain (loss) on risk management contracts		**5,569**		(472)
Gain on risk management contracts	**$**	**5,911**	$	5,648

The table below summarizes the Company's outstanding commodity contracts as at March 31, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2017						
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap	$ 529
Oil	500 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap	316
Oil	500 bbls/d	April 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap	323
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap	(119)
Oil	1,000 bbls/d	April 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap	(415)
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar	(238)
Oil	500 bbls/d	April 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar	(299)
Oil	1,000 bbls/d	April 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call	(277)
2018						
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call	(210)
Total						$ (390)

Current portion of fair value of contracts	$ (233)
Non-current portion of fair value of contracts	$ (157)

As at March 31, 2017, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $5.6 million increase in fair value of these contracts and increase in income for the period. A 10% increase to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $8.1 million decrease in fair value of these contracts and decrease in income for the period.

The table below summarizes commodity contracts the Company entered into subsequent to March 31, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap

15. SUPPLEMENTARY INFORMATION

(a) The following table summarizes the cash interest paid:

	Three months ended March 31, 2017	Three months ended March 31, 2016
Cash interest paid	**$ 162**	$ 835

(b) The following table summarizes finance costs included on the statement of comprehensive income:

		Three months ended March 31, 2017		Three months ended March 31, 2016
Interest and financing charges	**$**	**162**	$	835
Accretion of decommissioning liabilities		**387**		366
Finance costs	**$**	**549**	$	1,201

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

		Three months ended March 31, 2017		Three months ended March 31, 2016
Changes in non-cash working capital				
Trade and other receivables	**$**	**(501)**	$	2,132
Inventory		**(105)**		448
Prepaid expenses and deposits		**3**		436
Accounts payable and accrued liabilities		**1,648**		(3,286)
Changes in non-cash working capital	**$**	**1,045**	$	(270)
Relating to:				
Operating activities	**$**	**1,904**	$	656
Investing activities	**$**	**(859)**	$	(926)