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NEWS RELEASE **November 7, 2017**

BLACKPEARL ANNOUNCES THIRD 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 and nine months ended September 30, 2017.

Q3 Highlights:

- At Onion Lake, excellent progress was made during the quarter on the construction of the 6,000 barrel per day (bbl/d) phase 2 thermal expansion. Construction is currently ahead of schedule and costs are in line with our original estimates of $185 million. Fabrication of the modules for the central processing facilities and well pads were approximately 85% complete at the end of the quarter and the modules continue to be shipped out to site for assembly and tie-in. All 14 horizontal production wells have been drilled as well as 29 of 39 planned steam injection wells. Drilling should be complete by the end of November. We now anticipate construction to be completed and initial steam injection to occur as early as the end of Q1 2018, with first oil expected in Q3 2018. We anticipate reaching peak production approximately 12 months after initial steam injection, a similar timeline achieved for phase 1.

- We successfully completed a planned turnaround on the phase 1 thermal facilities at Onion Lake in Q3 2017. Thermal production from Onion Lake was temporarily impacted by the turnaround as well as the temporary shut-in of phase 1 wells to allow for offset drilling of the phase 2 wells. The thermal facilities and wells were successfully restarted and current production is back up to design capacity of 6,000 bbl/d.

- At Blackrod, we continued to successfully operate and produce the SAGD pilot. The pilot produced 500 bbl/d in Q3 and cumulatively the well pair has produced 600,000 barrels of oil. We continue to operate the pilot to fully understand the well characteristics for an extended period. Additional core hole drilling is planned this winter at Blackrod to further define our development plans for the area.

- Production for the quarter averaged 9,072 bbls/d, 13% lower than Q2 2017 volumes. Lower volumes were mainly attributable to the planned maintenance work on the Onion Lake thermal facilities; current production is back over 10,000 bbls/d.

- Total capital investment for the quarter was $58.6 million, almost all of which related to the Onion Lake thermal expansion project.

- Oil and gas sales during the first nine months of 2017 increased 46% to $108 million and adjusted funds flow (a non-GAAP measure) increased 40% to $41 million. For the nine months ended September 30, 2017, the Company recognized net income of $11 million.

- The Company maintained a strong liquidity position with net debt of $81 million, while its $120 million bank credit facilities remained undrawn.

- Initial 2018 guidance demonstrates the significant impact the Onion Lake thermal expansion is expected to have on our operations as we expect to exit 2018 at about 14,000 bbl/d, approximately 40% higher than our current production.

John Festival, President of BlackPearl commenting on Q3 activities emphasized that "Construction of the Onion Lake thermal expansion is going very well. We are ahead of schedule and if we continue to get favourable weather conditions we should be able to beat our target start-up date of mid 2018. Additionally, with the financing we put in place in Q2 the project is fully funded. This is a significant step for us to add 6,000 barrels of oil per day of low cost production to our existing 10,000 barrel per day base with no dilution to our shareholders. The Onion Lake thermal assets will have low sustaining capital requirements and will generate significant free cash flow which will allow for debt repayment and continued expansion at Onion Lake and other areas. We are going to see the full effect of phase 2 in 2019 when our production should be in the range of 15,000 to 16,000 boe/d with 12,000 boe/d coming from Onion thermal. In addition, we will start working on a further expansion of Onion thermal in 2019. We currently have enough reserves and resource to keep the expanded project at full design capacity for more than 20 years."

Financial and Operating Highlights

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Daily sales volumes				
Oil (bbl/d)	8,486	10,251	9,472	9,236
Bitumen (bbl/d) [1]	500	565	493	567
	8,986	10,816	9,965	9,803
Natural gas (mcf/d)	516	815	595	836
Combined (boe/d) [2]	9,072	10,951	10,064	9,942
Product pricing ($) (before the effects of hedging transactions)				
Crude oil - per bbl	42.05	34.15	41.55	28.97
Natural gas - per mcf	1.31	2.10	2.18	1.72
Combined - per boe	41.71	33.87	41.26	28.69
Netback ($/boe)				
Oil and gas sales	41.71	33.87	41.26	28.69
Realized gain on risk management contracts	1.84	2.24	0.67	3.98
Royalties	(5.69)	(4.30)	(5.83)	(3.61)
Transportation	(2.33)	(2.11)	(2.55)	(2.08)
Operating costs	(16.46)	(12.13)	(15.43)	(12.55)
Netback [5]	19.07	17.57	18.12	14.43
($000's, except per share amounts)				
Revenue				
Oil and gas revenue – gross	32,894	32,367	107,800	73,706
Net income (loss) for the period	(5,445)	556	10,687	(17,711)
Per share, basic and diluted	(0.02)	0.00	0.03	(0.05)
Adjusted funds flow[3]	13,412	14,202	40,515	28,977
Cash flow from operating activities [4]	10,775	16,441	40,641	27,412

Capital expenditures	58,592	1,753	121,961	4,775
Working capital deficiency (surplus), end of period	8,445	(3,384)	8,445	(3,384)
Long term debt	72,738	67,000	72,738	67,000
Net debt (6)	81,183	63,616	81,183	63,616
Shares outstanding, end of period	336,267,235	335,646,559	336,267,235	335,646,559

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

(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. See non-GAAP measures.

(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. See non-GAAP measures.

Production

Oil and gas production averaged 9,072 barrels of oil equivalent per day (boe/day) in the third quarter of 2017, a 17% decrease compared with the third quarter of 2016. The decrease reflects the shutdown of the Onion Lake thermal facilities for three weeks during the quarter for planned maintenance and inspection work as well as the temporary shut-in of existing producing phase 1 wells to allow for offset drilling of the phase 2 wells.

Average Daily Sales Volume

	Three months ended September 30,		Nine months ended September 30,	
(boe/day)	2017	2016	2017	2016
Onion Lake - thermal	4,553	6,472	5,511	5,319
Onion Lake - conventional	1,942	2,162	2,058	2,177
Mooney	1,157	665	1,068	807
John Lake	774	885	794	872
Blackrod	500	565	493	567
Other	146	202	140	200
	9,072	10,951	10,064	9,942

Financial Results

Oil and natural gas sales were $32.9 million in the third quarter of 2017, comparable to the $32.4 million in the same period in 2016. A 23% increase in our average realized sale price was offset by a 17% decrease in production volumes (on a boe basis) in Q3 2017 compared to the same period in 2016. Oil and natural gas sales for the nine months ended September 30, 2017 increased 46% to $107.8 million compared to the same period in 2016 and was mainly attributable to a 44% increase in our average realized price.

Our realized oil price (before the effects of risk management activities) in Q3 2017 was $42.05 per barrel compared to $34.15 per barrel for the same period in 2016. The increase in our realized wellhead price reflects higher WTI reference oil prices in Q3 2017 compared with Q3 2016 (US$48.21/bbl vs US$44.94/bbl) and tighter heavy oil differentials (US$9.96/bbl vs US$13.51/bbl), offset by a stronger Canadian dollar relative to the US dollar ($0.799 vs $0.766).

Operating costs in Q3 2017 were $13 million, down 4% from Q2 2017 but 12% higher than Q3 2016. The increase from 2016 is mainly attributable to higher conventional production costs related to the restart of the ASP flood at Mooney in 2017. Thermal production costs decreased in Q3 2017 compared to Q2 2017, which is primarily attributable to lower gas consumption costs due to lower natural gas prices (AECO gas prices were $1.38/GJ in Q3 2017 vs $2.64/GJ in Q2 2017), partially offset by turnaround costs related to the Onion Lake thermal facility.

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Conventional Production				
Production costs ($000s)	7,681	6,359	24,480	18,309
Per boe ($)	20.78	17.66	22.09	16.48
Thermal Production				
Production costs ($000s)	5,297	5,231	15,833	13,937
Per boe ($)	12.65	8.79	10.52	9.56
Energy costs	3.59	3.15	4.04	3.37
Non-energy costs	9.06	5.64	6.48	6.19
Total Production				
Production costs ($000s)	12,978	11,590	40,313	32,246
Per boe ($)	16.46	12.13	15.43	12.55

Stronger crude oil prices offset by reduced production volumes in Q3 2017 resulted in adjusted funds flow of $13.4 million compared to $14.2 million in Q3 2016.

Capital spending was $59 million in Q3 2017 with the majority of spending on the Onion Lake thermal expansion project.

At September 30, 2017, the Company had net debt of $81 million, made up primarily of the $75 million second lien notes that were issued in the second quarter. At September 30, 2017, the Company had not drawn on its $120 million of available bank credit facilities.

Guidance

Our plan for the remainder of 2017 is unchanged from our previous guidance update. We are still planning to spend between $195 and $200 million on capital projects with the focus being the expansion of the Onion Lake thermal project.

The capital program will be funded from a combination of our anticipated adjusted funds flow, proceeds from the issuance of the $75 million senior secured second lien notes and our undrawn senior credit facilities. Adjusted funds flow is expected to be between $55 and $60 million, up from our previous guidance of $52 to $57 million. The increase in adjusted funds flow is primarily attributable to higher forecast oil prices than what we used in previous guidance updates. For the remainder of the year we have assumed a WTI oil price of US$51.00, heavy oil differential of US$12.00 and a US$ to Cdn$ exchange rate of $0.81. Year-end 2017 debt levels are anticipated to be between $135 and $140 million, down from our previous guidance of $140 and $145 million. The decrease in year-end debt levels reflects an increase in forecasted adjusted funds flow for the remainder of the year.

We anticipate oil and gas production to average approximately 10,100 boe/d in 2017, which is within the range from our previous guidance.

2018 Initial Guidance
Capital spending in 2018 is expected to be between $60 and $65 million. The focus at the beginning of 2018 will be on completing construction of phase 2 of the Onion Lake thermal project. We expect to complete construction and initiate steam injection in late Q1 2018. For the remainder of 2018, we plan to resume drilling on some of our conventional heavy oil projects (approximately 20 wells), commence drilling a sustaining well pad for the Onion Lake thermal project and undertaking additional delineation drilling on our Blackrod lands.

We are planning to fund a significant portion of these capital costs with our anticipated adjusted funds flow, which we are budgeting to be between $50 and $55 million, supplemented with advances from our existing senior credit facilities. Year-end 2018 debt levels are anticipated to be between $145 and $155 million. Oil and gas production is expected to average between 11,000 and 12,000 boe/d in 2018. Exit production levels are expected to be approximately 14,000 boe/d.

Our 2018 guidance is based on a WTI oil price of US$52, a heavy oil differential of US$14.50, AECO natural gas price of $2.50/GJ and foreign exchange of US$1 = C$0.80. Currently, the WTI oil price is over US$57 and the heavy oil differential is approximately US$14 per barrel.

Long-Term Strategic Plan
The Company has reviewed its long-term strategic plan beyond 2018. Due to the prolonged period of low crude oil prices, the Company is planning to accelerate the expansion of the Onion Lake thermal project and defer the first phase of commercial development of the Blackrod SAGD project. In addition to crude oil prices, timing of the development of Blackrod is also dependent on anticipated capital and operating costs and the Company's ability to finance construction of the project. The Company's previous long-range plan had commercial development at Blackrod commencing within the next five years. Now, development of Blackrod will likely not begin until 2023 unless crude oil prices sufficiently improve or the Company finds a partner to participate in the development before then.

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources, including many factors beyond the control of the Company. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. See "Risk Factors – Operational Risks - Uncertainty of Reserve and Contingent Resource Estimates" and "Statement of Reserves Data and Other Oil and Gas Information – Significant Factors or Uncertainties" in the Company's Annual Information Form for the year ended December 31, 2016. Recognition of oil and gas reserves in Canada is based on definitions from the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). In order to be classified as reserves the COGE Handbook requires, among other things, significant spending on development of a project to commence within three years for proved reserves to be recognized, or within five years for probable reserves to be recognized.

As at December 31, 2016 the Company's independent reserves evaluator, Sproule Unconventional Limited

(Sproule) assigned approximately 180 million barrels of probable undeveloped reserves (the Company's working interest, before royalties) with a net present value, discounted at 10%, of approximately $610 million to the Blackrod SAGD project. Due to the delay in the timing of development of Blackrod and the COGE Handbook guidelines on the recognition of reserves, this will result in the reclassification of these probable undeveloped reserves to contingent resources. Because the Company is accelerating the expansion at Onion Lake the Company may be in a position to recognize additional reserves at Onion Lake that are currently classified as contingent resource. Any changes to the Company's reserves will be reflected in the 2017 reserves evaluation prepared by Sproule, which is expected to be released in February 2018.

The 2017 third 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 "adjusted funds flow", "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.

Adjusted funds flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs, decommissioning costs, debt repayments and other financial obligations. Adjusted funds flow is defined as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Adjusted funds flow is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The Company previously referred to "adjusted funds flow" as "funds flow from operations".

The following table reconciles non-GAAP measure adjusted funds flow to cash flow from operating activities, the nearest GAAP measure:

	Three months ended September 30,		Nine months ended September 30,	
($000s)	2017	2016	2017	2016
Cash flow from operating activities	10,775	16,441	40,641	27,412
Changes in non-cash working capital related to operations	2,197	(2,277)	(691)	1,011
Decommissioning costs	440	38	565	554
Adjusted funds flow	13,412	14,202	40,515	28,977

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 barrel of oil equivalent basis. 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, 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 $185 million to construct the phase 2 expansion of the Onion Lake thermal project and the estimated late Q1 2018 completion date and the estimated timing to reach peak production rates, the estimated 2018 exit production guidance of 14,000 barrels of oil per day, production estimates of 15,000 to 16,000 boe/d for 2019, the expectation that the Onion lake project will generate significant free cash flows and all the information under *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. Further information regarding these risk factors may be found under "Risk Factors" in the Annual Information Form, which can be accessed on SEDAR at www.sedar.com.

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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This is information that BlackPearl Resources Inc. is obliged to make public pursuant to the EU Market Abuse Regulation and the Swedish Securities Markets Act. The information was submitted for publication at 3:00 p.m. Mountain Time on November 7, 2017.

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 and nine months ended September 30, 2017. These results are being compared with the three and nine months ended September 30, 2016. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 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 "adjusted funds flow", "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.

Adjusted funds flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs, decommissioning costs, debt repayments and other financial obligations. Adjusted funds flow is defined as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Adjusted funds flow is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. The Company previously referred to "adjusted funds flow" as "funds flow from operations".

The following table reconciles non-GAAP measure adjusted funds flow to cash flow from operating activities, the nearest GAAP measure.

	2017			2016	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2017**	2016
Cash flow from operating activities (1)	**10,775**	15,080	14,786	16,441	**40,641**	27,412
Decommissioning costs incurred	**440**	83	42	38	**565**	554
Changes in non-cash working capital related to operations	**2,197**	(984)	(1,904)	(2,277)	**(691)**	1,011
Adjusted funds flow (2)	**13,412**	14,179	12,924	14,202	**40,515**	28,977

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. 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, current portion of fair value of risk management assets less accounts payable and accrued liabilities, current portion of decommissioning liabilities and current portion of 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)	**September 30, 2017**	December 31, 2016
Long-term debt (1)	**72,738**	-
Add (deduct) working capital:		
Cash and cash equivalents	**(24,102)**	(5,368)
Trade and other receivables	**(15,611)**	(13,391)
Inventory	**(245)**	(46)
Prepaid expenses and deposits	**(1,067)**	(705)
Fair value of risk management assets	**(1,425)**	-
Accounts payable and accrued liabilities	**48,657**	17,950
Current portion of decommissioning liabilities	**400**	644
Fair value of risk management liabilities	**1,838**	5,507
Net debt (2)	**81,183**	4,591

(1) Long-term debt is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Net debt 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 these 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.

This MD&A makes reference to the term "EBITDA". EBITDA or EBITDA (adjusted) is a non-GAAP measure defined under the Company's lending agreement. It is used to calculate a debt to EBITDA ratio which determines applicable margins applied to interest rates for any advances made and the Company is limited to a maximum debt to EBITDA ratio under the lending agreement. Management does not use this measure to assess performance or liquidity of the Company as it does with the other non-GAAP measures above.

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 November 7, 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. The second phase is currently under construction;
- 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 in 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 third quarter of 2017, our primary focus was the continued construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Construction is currently ahead of schedule and costs are in line with our original estimates of approximately $185 million. We now anticipate construction to be completed and initial steam injection to occur as early as the end of Q1 2018, with first oil expected in Q3 2018. Peak production is expected approximately 12 months after initial steam injection, a similar timeline achieved for phase 1. As of September 30, 2017, approximately 85% of module fabrications for the second phase plant facilities and well pads were completed. The modules are currently being shipped out to site for assembling and tie-in and all phase 2 drilling is expected to be completed by the end of November.

- Crude oil prices were higher in the first nine months of 2017, with WTI oil prices averaging US$49.47 per bbl during the first nine months of 2017 compared to US$41.33 per bbl during the same period in 2016.

- During the third quarter of 2017, oil and gas production averaged 9,072 boe/d; a decrease compared to the second quarter of 2017. This decrease in production quarter over quarter was mainly attributable to a planned three week turnaround and inspection at the Onion Lake thermal facility that began in late June and carried into July. The turnaround was planned to coincide with drilling some of the phase two wells to reduce the amount of facility down time. The turnaround resulted in a temporary decrease in production at the Onion Lake thermal facility during the quarter and production is expected to return to full rates in the fourth quarter.

- Capital expenditures during the first nine months of 2017 were $125.4 million, with approximately $116.0 million spent at the Onion Lake thermal project related to construction of the second phase of the project, $4.3 million spent at John Lake related to the drilling of two horizontal heavy oil wells, $1.8 million at Mooney related to bringing shut-in production back online, $1.1 million as Onion Lake primary related to drilling five gross (three net) conventional heavy oil wells and $2.2 million spent in other areas. The Company also completed dispositions of non-producing properties for proceeds totaling $3.4 million during the first nine months of 2017.

- Oil and gas sales during the first nine months of 2017 increased 46% to $108 million, cash flow from operating activities were $41 million and adjusted funds flow (a non-GAAP measure) were $41 million. For the nine months ended September 30, 2017, the Company recognized net income of $11 million.

- During the first nine months of 2017, 318,340 common shares were issued pursuant to the exercise of stock options, which generated net proceeds of $0.3 million for the Company. The Company did not undertake any equity issuances during the first nine months of 2017.

- At September 30, 2017, the Company had a working capital deficiency of $8.4 million, $75 million senior secured notes outstanding and had not drawn any amounts under its existing senior credit facilities; leaving $120 million available to be drawn.

SELECTED QUARTERLY INFORMATION

	2017			2016				2015
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31
Production (boe/d) [(1)]	**9,072**	**10,386**	**10,753**	**10,479**	10,951	9,698	9,166	9,521
Oil and gas sales	**32,894**	**37,702**	**37,204**	**35,360**	32,367	28,318	13,021	22,630
Oil sales ($/bbl)	**42.05**	**41.93**	**40.75**	**38.83**	34.15	34.44	16.77	27.65
Gas sales ($/mcf)	**1.31**	**2.58**	**2.50**	**2.90**	2.10	1.29	1.77	2.91
Oil and gas sales ($/boe)	**41.71**	**41.65**	**40.48**	**38.61**	33.87	34.03	16.67	27.45
Production & transportation costs	**14,815**	**15,926**	**16,233**	**13,550**	13,603	12,246	11,736	15,666
Production costs ($/boe)	**16.46**	**14.97**	**15.00**	**12.11**	12.13	13.23	12.35	17.77
Transportation costs ($/boe)	**2.33**	**2.62**	**2.67**	**2.69**	2.11	1.48	2.68	1.23
Gain (loss) on risk management contracts								
Realized	**1,448**	**(34)**	**342**	**578**	2,137	1,958	6,120	10,334
Unrealized	**(8,091)**	**5,724**	**5,569**	**(5,676)**	(538)	(8,597)	(472)	1,778
Net income (loss)	**(5,445)**	**8,318**	**7,814**	**(2,217)**	556	(8,945)	(9,322)	(31,172)
Per share, basic and diluted ($)	**(0.02)**	**0.02**	**0.02**	**(0.01)**	0.00	(0.03)	(0.03)	(0.09)
Capital expenditures	**58,592**	**53,434**	**13,356**	**6,150**	1,753	945	2,077	1,665
Adjusted funds flow [(2)]	**13,412**	**14,179**	**12,924**	**15,798**	14,202	11,497	3,278	10,898
Cash flow from operating activities	**10,775**	**15,080**	**14,786**	**15,079**	16,441	7,184	3,787	12,179
Long-term debt	**72,738**	**72,320**	**-**	**-**	67,000	80,000	86,000	88,000
Total assets (end of period)	**845,946**	**822,325**	**737,735**	**732,404**	773,206	782,591	795,336	808,344
Shares outstanding (000s)	**336,267**	**336,251**	**336,196**	**335,949**	335,647	335,647	335,638	335,638
Weighted average shares outstanding								
Basic	**336,266**	**336,226**	**336,157**	**335,733**	335,646	335,641	335,638	335,638
Diluted	**338,744**	**339,019**	**340,700**	**340,686**	337,959	335,641	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) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

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 cash generating unit ("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

	YTD		2017			2016			
	2017	2016	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices									
West Texas Intermediate (WTI) (US$/bbl)	49.47	41.33	48.21	48.29	51.91	49.29	44.94	45.59	33.45
Western Canadian Select (WCS) (Cdn$/bbl)	49.06	36.31	47.88	49.96	49.36	46.62	41.02	41.61	26.31
Differential – WCS/WTI (US$/bbl)	11.93	13.88	9.96	11.14	14.61	14.34	13.51	13.30	14.32
Differential - WCS/WTI (%)	24.1%	33.6%	20.7%	23.1%	28.1%	29.1%	30.1%	29.2%	42.8%
Average Natural Gas Prices									
AECO gas (Cdn$/GJ)	2.19	1.76	1.38	2.64	2.55	2.93	2.20	1.33	1.74
Average Foreign Exchange (US$ per Cdn$1)	0.765	0.756	0.799	0.743	0.756	0.750	0.766	0.776	0.727

Crude oil prices are based on supply and demand for oil that 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.

Crude oil prices during the third quarter were comparable to the second quarter of 2017 and current year prices remain higher than the comparable periods in 2016. WTI oil prices averaged US$48.21 per bbl in the third quarter of 2017 compared to US$48.29 per bbl in the second quarter of 2017 and US$44.94 per bbl in the third quarter of 2016. For the first nine months of 2017, WTI oil prices averaged US$49.47 per bbl, an increase from US$41.33 per bbl in the same period in 2016.

The heavy oil differential (WTI oil prices compared to WCS oil prices) improved in the third quarter of 2017. Heavy oil differentials averaged US$9.96 per bbl in the third quarter of 2017 compared to US$11.14 per bbl in the second quarter of 2017. Heavy oil differentials have narrowed in 2017 relative to 2016. The lower differential in 2017 has been attributed to temporarily shut-in heavy oil production in Canada due to planned and unplanned maintenance, decreased US imports of heavier grades of oil from OPEC countries due to their decision to reduce oil output and lower Mexican and Venezuela heavy oil production, all resulting in greater demand for Canadian heavy oil.

Canadian natural gas prices decreased significantly during the third quarter of 2017 averaging $1.38/GJ compared to $2.64/GJ in the second quarter of 2017. The decrease has been attributed to infrastructure maintenance work and pipeline restrictions. 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, therefore, this significant decrease in natural gas prices during the third quarter resulted in lower fuel gas consumption costs in these areas compared to prior quarters in 2017.

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 was fairly consistent against the US dollar in the first nine months of 2017 compared to the same period in 2016. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.76 during the first nine months of 2017 and 2016. More recently, the Canadian dollar has strengthened relative to the US dollar (in the range of $0.78 - $0.81 to the US dollar) which will negatively impact our future revenues and cash flows.

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 adjusted funds flow for 2017 (1) (2):

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	472
Realized crude oil price (Cdn$/bbl)	1.00	786
US $ to Canadian $ exchange rate	0.01	253

(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) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

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

	2017			2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Daily production/sales volumes						
Oil (bbls/d)	**8,486**	9,843	10,105	10,251	**9,472**	9,236
Bitumen – Blackrod (bbls/d) (2)	**500**	437	542	565	**493**	567
Combined (bbls/d)	**8,986**	10,280	10,647	10,816	**9,965**	9,803
Natural gas (Mcf/d)	**516**	633	638	815	**595**	836
Total production (boe/d) (1)	**9,072**	10,386	10,753	10,951	**10,064**	9,942
Product pricing (excluding risk management activities) (2)						
Oil ($/bbl)	**42.05**	41.93	40.75	34.15	**41.55**	28.97
Natural gas ($/Mcf)	**1.31**	2.58	2.50	2.10	**2.18**	1.72
Combined ($/boe) (1)	**41.71**	41.65	40.48	33.87	**41.26**	28.69
Sales ($000s) (2)						
Oil and gas sales – gross	**32,894**	37,702	37,204	32,367	**107,800**	73,706
Royalties	**(4,490)**	(5,317)	(5,422)	(4,111)	**(15,229)**	(9,269)
Oil and gas revenues – net (3)	**28,404**	32,385	31,782	28,256	**92,571**	64,437

(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 in the third quarter of 2017 were $32.9 million, comparable to $32.4 million in the same period in 2016. This was attributable to a 23% increase in our average realized sale price, offset by a 17% decrease in production volumes (on a boe basis) in the third quarter of 2017 compared to the same period in 2016. Oil and natural gas sales for the nine months ended September 30, 2017 increased 46% compared to the same period in 2016 and was mainly attributable to a 44% increase in our average realized price.

Higher WTI crude oil prices and narrower heavy oil differentials contributed to an increase in our realized crude oil sales prices in the third quarter of 2017 compared to the same period in 2016. Our average oil wellhead sales price in the third quarter of 2017, prior to the impact of risk management activities, was $42.05 per bbl compared with $34.15 per bbl in the same period in 2016.

The decrease in production during the third quarter of 2017 compared to the second quarter of 2017 and the third quarter of 2016 is mainly attributable to a planned three week turnaround and inspection at the Onion Lake thermal facility that began in late June and carried into July. The turnaround was planned to coincide with drilling some of the phase two wells to reduce the amount of facility down time. The turnaround resulted in a temporary decrease in production at the Onion Lake thermal facility during the third quarter; however, production is expected to return to full rates in the fourth quarter.

With the improvement in crude oil prices, during the first nine months of 2017 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 contributed to a 74% increase in oil production in Q3 2017 from the Mooney field compared to Q3 2016.

On a boe basis, 99% of the Company's oil and natural gas production in the third quarter of 2017 was heavy oil or bitumen. The Onion Lake area accounted for 72% of total production in the third quarter of 2017.

		2017		2016	Nine months ended September 30	
Production by area (boe/d)	**Q3**	Q2	Q1	Q3	**2017**	2016
Onion Lake - thermal	**4,553**	5,816	6,182	6,472	**5,511**	5,319
Onion Lake - conventional	**1,942**	2,087	2,147	2,162	**2,058**	2,177
Mooney	**1,157**	1,103	942	665	**1,068**	807
John Lake	**774**	801	808	885	**794**	872
Blackrod	**500**	437	542	565	**493**	567
Other	**146**	142	132	202	**140**	200
Total production	**9,072**	10,386	10,753	10,951	**10,064**	9,942

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 nine months of 2017, the pilot well produced an average of 493 bbls/d of bitumen and the net revenues capitalized in the first nine months of 2017 were a loss of $0.1 million ($0.3 million loss in the first nine months of 2016).

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 loss of $6.6 million on its risk management contracts during the third quarter of 2017, consisting of a $1.5 million realized gain on the contracts and an unrealized loss of $8.1 million.

		2017		2016	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2017**	2016
Realized gain (loss) on risk management contracts	**1,448**	(34)	342	2,137	**1,756**	10,215
Per boe ($)	**1.84**	(0.04)	0.37	2.24	**0.67**	3.98
Unrealized gain (loss) on risk management contracts	**(8,091)**	5,724	5,569	(538)	**3,202**	(9,607)

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap
Oil	500 bbls/d	October 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap
Oil	1,000 bbls/d	October 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call
2018					
Oil	2,000 bbls/d	January 1 to March 31	CDN$ WCS/WTI Differential	CDN$ 16.25/bbl	Swap
Oil	2,000 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 49.55/bbl	Swap
Oil	1,000 bbls/d	January 1 to June 30	US$ WTI	US$ 45.00/bbl to 57.75/bbl	Collar
Oil	1,500 bbls/d	January 1 to June 30	US$ WTI	US$ 40.00/bbl to 50.00/bbl	Collar
Oil	500 bbls/d	July 1 to September 30	US$ WTI	US$ 40.00/bbl to 58.00/bbl	Collar
Oil	500 bbls/d	July 1 to September 30	US$ WTI	US$ 45.00/bbl to 54.00/bbl	Collar
Oil	1,000 bbls/d	July 1 to September 30	US$ WTI	US$ 40.00/bbl to 60.00/bbl	Collar
Oil	1,000 bbls/d	July 1 to September 30	US$ WTI	US$ 45.00/bbl to 57.00/bbl	Collar
Oil	2,200 bbls/d	July 1 to December 31	US$ WTI	US$ 40.00/bbl to 51.00/bbl	Collar
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call
2019					
Oil	500 bbls/d	January 1 to March 31	US$ WTI	US$ 40.00/bbl to 60.00/bbl	Collar
Oil	500 bbls/d	January 1 to March 31	US$ WTI	US$ 43.25/bbl to 57.00/bbl	Collar
Oil	1,600 bbls/d	January 1 to March 31	US$ WTI	US$ 40.00/bbl to 58.25/bbl	Collar

At September 30, 2017, these contracts had a net fair value of $2.8 million in a derivative liability position. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $11.0 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 $12.8 million decrease in fair value.

Royalties

		2017		2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Royalties ($000s)	**4,490**	5,317	5,422	4,111	**15,229**	9,269
Per boe ($)	**5.69**	5.87	5.90	4.30	**5.83**	3.61
As a percentage of oil and gas sales	**14%**	14%	15%	13%	**14%**	13%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased as well as overriding royalties paid to third parties as a result of contractual arrangements. 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. Royalty rates are generally dependent on commodity prices, oil quality and well productivity. Enhanced oil recovery projects (such as our Onion Lake thermal project) typically pay lower royalties until the project recovers its capital costs and then royalty rates increase.

Royalties were $4.5 million in the third quarter of 2017, an increase from $4.1 million in the same period in 2016. Royalties as a percentage of oil and gas sales increased to 14% in the third quarter of 2017 from 13% in the same period in 2016. The increase in royalty rates in 2017 is attributable to the sale, in late 2016, of a 1.75% royalty on substantially all of our current and future Onion Lake production.

Transportation Costs

	2017			2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Conventional Production						
Transportation costs ($000s)	**570**	605	407	206	**1,582**	651
Per boe ($)	**1.54**	1.61	1.12	0.57	**1.43**	0.59
Thermal Production						
Transportation costs ($000s)	**1,267**	1,769	2,043	1,807	**5,079**	4,688
Per boe ($)	**3.02**	3.34	3.67	3.04	**3.38**	3.22
Total Production						
Transportation costs ($000s)	**1,837**	2,374	2,450	2,013	**6,661**	5,339
Per boe ($)	**2.33**	2.62	2.67	2.11	**2.55**	2.08

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 decreased in the third quarter of 2017 to $1.8 million from $2.4 million in the second quarter of 2017. The decrease in transportation costs is primarily attributable to decreased production from the first phase of the Onion Lake thermal project as a result of a planned facility turnaround and inspection during the quarter. Thermal transportation costs are expected to return to normal amounts in the fourth quarter.

Production Costs

	2017			2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Conventional Production						
Production costs ($000s)	**7,681**	7,941	8,858	6,359	**24,480**	18,309
Per boe ($)	**20.78**	21.11	24.43	17.66	**22.09**	16.48
Thermal Production						
Production costs ($000s)	**5,297**	5,611	4,925	5,231	**15,833**	13,937
Per boe ($)	**12.65**	10.60	8.85	8.79	**10.52**	9.56
Energy costs	**3.59**	4.16	4.27	3.15	**4.04**	3.37
Non-energy costs	**9.06**	6.44	4.58	5.64	**6.48**	6.19
Total Production						
Production costs ($000s)	**12,978**	13,552	13,783	11,590	**40,313**	32,246
Per boe ($)	**16.46**	14.97	15.00	12.13	**15.43**	12.55

The most significant components of our production costs are labor, utilities, maintenance and workover costs, chemicals (including polymer), property taxes and the cost of natural gas (thermal operations).

Total production costs increased 12% in the third quarter of 2017 to $13.0 million from $11.6 million in the same period in 2016. On a per boe basis, total production costs increased 36% in the third quarter of 2017 to $16.46 per boe from $12.13 per boe in the same period in 2016.

Conventional production costs increased in the third quarter of 2017 compared to the same period in 2016. The re-initialization of a portion of the ASP flood at Mooney resulted in an increase in chemical and injection costs during the third quarter of 2017.

Thermal production costs decreased in the third quarter of 2017 compared to the second quarter of 2017, which is primarily attributable to lower natural gas consumption costs as a result of lower natural gas prices in the quarter. These lower natural gas costs were partially offset by costs related to a planned three week turnaround and inspection that began in late June and carried into July at the Onion Lake thermal facility. The turnaround resulted in a temporary decrease in production at the Onion Lake thermal facility, which caused thermal production costs on a boe basis to increase in third quarter of 2017 compared to prior periods. Thermal production costs per boe are expected to return to normal rates in the fourth quarter.

***Operating Netback* (1) (2 (3)**

Three months ended

	Q3 2017		Q2 2017		Q1 2017		Q3 2016	
	$000s	**$/boe**	$000s	$/boe	$000s	$/boe	$000s	$/boe
Oil and gas sales	**32,894**	**41.71**	37,702	41.65	37,204	40.48	32,367	33.87
Royalties	**4,490**	**5.69**	5,317	5.87	5,422	5.90	4,111	4.30
Transportation costs	**1,837**	**2.33**	2,374	2.62	2,450	2.67	2,013	2.11
Production costs	**12,978**	**16.46**	13,552	14.97	13,783	15.00	11,590	12.13
Operating netback before realized risk management contracts	**13,589**	**17.23**	16,459	18.19	15,549	16.91	14,653	15.33
Realized gain on risk management contracts	**1,448**	**1.84**	(34)	(0.04)	342	0.37	2,137	2.24
Operating netback after realized risk management contracts	**15,037**	**19.07**	16,425	18.15	15,891	17.28	16,790	17.57

Nine months ended

	September 2017		September 2016	
	$000s	**$/boe**	$000s	$/boe
Oil and gas sales	**107,800**	**41.26**	73,706	28.69
Royalties	**15,229**	**5.83**	9,269	3.61
Transportation costs	**6,661**	**2.55**	5,339	2.08
Production costs	**40,313**	**15.43**	32,246	12.55
Operating netback before realized risk management contracts	**45,597**	**17.45**	26,852	10.45
Realized gain on risk management contracts	**1,756**	**0.67**	10,215	3.98
Operating netback after realized risk management contracts	**47,353**	**18.12**	37,067	14.43

(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. See non-GAAP financial measures.*
(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. (Q3 2017 – 8,572 boe/d; Q2 2017 – 9,948 boe/d; Q1 2017 – 10,211 boe/d; Q3 2016 – 10,386 boe/d; Nine months ended September 30, 2017 – 9,571 boe/d; Nine months ended September 30, 2016 – 9,375 boe/d).*
(3) *Excludes deferred consideration amount recognized during the period.*

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 third quarter of 2017 to $17.23 per boe from $15.33

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)

	2017			2016	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2017**	2016
Gross G&A expense	**1,955**	2,033	3,023	1,792	**7,011**	5,930
Operator recoveries	**(412)**	(219)	(236)	(178)	**(867)**	(617)
Net G&A expense	**1,543**	1,814	2,787	1,614	**6,144**	5,313
Per boe ($)	**1.96**	2.00	3.03	1.69	**2.35**	2.07

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Net general and administrative costs were comparable in the third quarter of 2017 to the same period in 2016. Higher salary and wage costs in the third quarter of 2017 compared to 2016 were offset by higher operator recoveries due to increased capital spending activity.

The increase in gross G&A expenses in the first nine months of 2017 compared to the same period in 2016 reflects higher staff compensation costs in 2017. As oil prices stabilized during 2017, previous salary reductions were rescinded and performance incentive payments to staff were made during the first quarter of the year.

Stock-Based Compensation

	2017			2016	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2017**	2016
Gross stock-based compensation	**599**	566	570	767	**1,735**	2,656
Recoveries from forfeitures	**-**	(21)	(5)	-	**(26)**	(48)
Net stock-based compensation	**599**	545	565	767	**1,709**	2,608
Per boe ($)	**0.76**	0.60	0.62	0.80	**0.65**	1.02

Stock-based compensation costs are non-cash charges that 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.

The decrease in gross stock-based compensation in the first nine months of 2017 compared to the same period in 2016 is primarily attributable to a decrease in the weighted average number of options outstanding during 2017. In the first nine months of 2017, 318,340 options were exercised, 1,887,000 options were granted, 339,999 options were forfeited and 1,294,500 options expired. Based on stock options and RSUs outstanding as at September 30, 2017, the Company has an unamortized stock based compensation expense of approximately $3.2 million, of which $0.6 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

		2017		2016	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2017**	2016
Gross interest & financing charges	**1,722**	632	162	986	**2,516**	2,739
Capitalized interest and financing charges	**(1,634)**	(272)	-	-	**(1,906)**	-
Net interest and financing charges	**88**	360	162	986	**610**	2,739
Accretion of decommissioning liabilities	**434**	390	387	357	**1,211**	1,084
Amortization of debt issuance costs	**206**	-	-	-	**206**	-
Total finance costs	**728**	750	549	1,343	**2,027**	3,823

Finance costs are made up of interest on our outstanding debt, standby fees on credit facilities available to us that are not currently being utilized, amortization of debt issuance costs, annual credit facilities renewal fees and accretion of decommissioning liabilities.

The increase in gross interest and financing charges in the third quarter of 2017 compared to the same period in 2016 is primarily attributed to the Company's issuance on June 30, 2017, of $75 million of senior secured second lien notes that bear interest at 8% per year.

During the third quarter of 2017, we capitalized $1.6 million in interest charges related to debt incurred for the construction of the second phase of the Onion Lake thermal project. During 2016, we did not capitalize any interest charges.

In addition to the $75 million second lien notes, we also have senior credit facilities provided by a syndicate of lenders. These credit facilities are floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on these credit facilities is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate charged on our senior credit facilities debt is expected to be 3.5 – 4.0% for the remainder of 2017 (assuming no other changes in market conditions). We have not entered into any financial instruments to fix the interest rate on our floating rate debt.

Depletion and Depreciation

		2017		2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Depletion and depreciation ($000s)	**9,568**	10,754	10,953	11,984	**31,275**	33,389
Per boe ($)	**12.13**	11.88	11.92	12.54	**11.97**	13.00

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased to $9.6 million in the third quarter of 2017 compared to $10.8 million in the second quarter of 2017 and $12.0 million in the third quarter of 2016. The decrease in depletion and depreciation in the third quarter of 2017 is primarily attributable to a decrease in production during the quarter.

There were no impairment losses or reversals recorded for the nine months ended September 30, 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.

Income Taxes

BlackPearl did not pay cash income taxes in the first nine 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. In addition, due to a change in the amount of previously unrecognized deferred tax assets, no net deferred tax provision was recorded for the first nine months of 2017.

RESULTS FROM OPERATIONS

	2017			2016	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2017**	2016
Net income (loss) ($000s)	**(5,445)**	8,318	7,814	556	**10,687**	(17,711)
Per share, basic ($)	**(0.02)**	0.02	0.02	0.00	**0.03**	(0.05)
Per share, diluted ($)	**(0.02)**	0.02	0.02	0.00	**0.03**	(0.05)

For the quarter ended September 30, 2017, the Company incurred a net loss of $5.4 million compared to net income of $0.6 million in the same period in 2016. The decrease in net income in the third quarter of 2017 compared to the same period in 2016 is primarily a result of unrealized losses on risk management contracts. For the nine months ended September 30, 2017, net income increased compared to the same period in 2016 primarily as a result of increased revenue from higher realized wellhead prices partially offset by higher royalties and production costs.

	2017			2016	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2017**	2016
Cash flow from operating activities	**10,775**	15,080	14,786	16,441	**40,641**	27,412
Adjusted funds flow (1)	**13,412**	14,179	12,924	14,202	**40,515**	28,977

(1) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

Adjusted funds flow decreased 6% to $13.4 million during the third quarter of 2017 compared to $14.2 million in the same period in 2016. The decrease in adjusted funds flow in 2017 is primarily attributable to increased production costs at Mooney as a result of the re-initiation of the ASP flood in 2017.

Cash flow from operating activities differs from adjusted funds flow principally due to the inclusion of decommissioning costs incurred and changes in non-cash working capital. For the three months ended September 30, 2017, cash flow from operating activities was lower than adjusted funds flow due to changes in non-cash working capital of $2.2 million and decommissioning costs incurred of $0.4 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company will generally utilize cashflow from operating activities and available credit facilities to fund its capital spending programs. In addition, from time to time the Company will seek additional capital in the form of debt, equity or the disposition of properties.

($000s)	**September 30, 2017**	December 31, 2016
Working capital deficiency	**8,445**	4,591
Long-term debt	**72,738**	-
Net debt (1)	**81,183**	4,591

(1) Net debt 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. See non-GAAP financial measures.

At September 30, 2017, the Company had working capital deficiency of $8.4 million, no amounts drawn on its $120 million credit facilities and had issued letters of credit in the amount of $20,000; leaving $120 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 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 any shortfall. The next scheduled Borrowing Base redetermination is to occur by November 30, 2017. The senior credit facilities have been provided on a revolving basis until May 27, 2018, at which time they may be extended at the lenders option. If the lenders elected not to renew the senior credit facilities, any amounts outstanding would convert to a term loan that would be due and payable in full by May 27, 2019.

The Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital is defined as current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the senior 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 3.3:1 at September 30, 2017 (December 31, 2016 – 7.2:1).

($000s, except working capital ratio)	**September 30, 2017**	December 31, 2016
Current assets per consolidated financial statements	**42,450**	19,510
Add: amount available to be drawn on credit facilities	**120,000**	117,500
Less: current risk management assets	**(1,425)**	-
Current assets for working capital ratio	**161,025**	137,010
Current liabilities per consolidated financial statements	**51,307**	24,505
Less: current risk management liabilities	**(1,838)**	(5,507)
Current liabilities for working capital ratio	**49,469**	18,998
Working capital ratio	**3.3**	7.2

The terms of the $75 million senior secured second lien notes we issued in June included certain other financial covenants the Company is required to comply with on an on-going basis. The Company is limited to a maximum total debt to EBITDA ratio of 4.5:1 at the end of each fiscal quarter. The Company is also limited to a maximum senior credit facilities debt to EBITDA ratio of 3.5:1 at the end of each fiscal quarter on or before December 31, 2018. After December 31, 2018, the Company is limited to maximum senior credit facilities debt to EBITDA ratio of 3:1. Total debt is defined as the Company's total debt outstanding excluding accounts payable and accrued liabilities, decommissioning liabilities, deferred consideration and liabilities under risk management contracts at the end of each fiscal quarter. Senior credit facilities debt is defined as any amounts drawn on the senior credit facilities plus any letters of credit outstanding. EBITDA is a non-GAAP measure and is defined as the Company's net income for the trailing 12 month period before financing charges, income taxes, all non-cash items including depletion and depreciation, accretion, future taxes, stock-based compensation, unrealized gains or losses on risk management contracts and write down or reversal of impairment of assets, income or losses attributable to extraordinary and non-recurring gains or losses and gains or losses from asset sales. The Company had a total debt to EBITDA ratio of 1.3:1 and a senior credit facilities debt to EBITDA ratio of 0.0:1 at September 30, 2017. In addition, the Company is required to pass an asset coverage test twice a year. The Company's net present value of proved reserves discounted at 10% must be at least 1.5 times of total debt.

At September 30, 2017, the Company was in compliance with all debt covenants.

During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Construction is currently ahead of schedule and costs are in line with our original estimates of approximately $185 million. The Company has entered into a fixed price agreement to fabricate the central processing facilities and pad facilities for this second phase. Proceeds from the issuance of the senior secured second lien notes, the Company's borrowing capacity on our existing senior credit facilities and expected cash flow from operating activities will be used to fund the construction of the second phase of our Onion Lake thermal project.

At September 30, 2017, there were 336,267,235 common shares issued and outstanding. In the first nine months of 2017, the Company issued 318,340 common shares for net proceeds of $0.3 million pursuant to the exercise of stock options.

The Company did not pay dividends on its common shares in the first nine months 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 facilities restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending during the third quarter of 2017 was $58.6 million, an increase from $1.8 million during the same period in 2016. The majority of the capital spending during the third quarter were related to the construction for the second phase of the Onion Lake thermal project.

		2017		2016	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2017**	2016
Land	**1,682**	3,157	1,865	302	**6,704**	744
Seismic	**32**	42	-	-	**74**	(5)
Drilling and completion	**22,884**	1,787	3,781	1,188	**28,452**	2,722
Equipment and facilities	**33,990**	48,446	7,707	204	**90,143**	1,248
Other	**4**	2	3	59	**9**	66
Total	**58,592**	53,434	13,356	1,753	**125,382**	4,775
Property acquisitions	**-**	-	-	-	**-**	-
Total capital expenditures	**58,592**	53,434	13,356	1,753	**125,382**	4,775
Proceeds on disposition	**-**	-	(3,421)	-	**(3,421)**	-
Net capital expenditures	**58,592**	53,434	9,935	1,753	**121,961**	4,775

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 September 30, 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)	213	788	579	437	421	-
Electrical service agreement (2)	294	585	119	119	119	1,868
Transportation service agreement (3)	34	135	135	33	-	-
Decommissioning liabilities (4)	79	428	346	8,919	1,634	65,101
Capital commitments (5)	6,090	5,000	5,000	-	-	-
Long-term debt (6)	-	-	-	75,000	-	-
Interest payments on long-term debt (6)	1,500	6,000	6,000	3,000	-	-
Total	8,210	12,936	12,179	87,508	2,174	66,969

(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 that 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 $76.5 million as at September 30, 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.

(6) The Company issued $75 million senior secured second lien notes bearing an interest rate of 8% payable quarterly in arrears and due on June 30, 2020.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt. 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 value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. 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).

See the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 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 September 30, 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 September 30, 2017 or 2016 except for key management compensation.

OUTSTANDING SHARE DATA, STOCK OPTIONS AND RESTRICTED SHARE UNITS

As at November 7, 2017, the Company had 336,267,235 common shares outstanding, 26,850,496 stock options outstanding and 1,710,000 restricted share units outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at November 7, 2017, the Company had not drawn any amounts under its existing senior credit facilities and had issued letters of credit in the amount of $20,000; leaving $119,980,000 available to be drawn under these credit facilities. The Company had $75,000,000 outstanding on its senior secured second lien notes on November 7, 2017.

PROPOSED TRANSACTIONS

As of November 7, 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 September 30, 2017. Additional disclosure has been provided on the sale of a royalty interest in note 10 of the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 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 continuing to evaluate the impact of IFRS 15 and currently expects that the standard will not have a material impact on the Company's consolidated financial statements, however; the Company is still evaluating the impact of IFRS 15 on deferred consideration. The Company is currently evaluating the enhanced disclosures requirements related to the disaggregation of revenues from contracts with customers, the Company's performance obligations and any significant judgements. The Company intends to adopt the new standard using the modified retrospective method at the date of adoption.

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 continuing to evaluate the impact of IFRS 9 and currently expects that the standard will not have a material impact on the Company's consolidated financial statements other than enhanced disclosure including any significant judgements.

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 identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. The Company is continuing to evaluate 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. Additional risk factors identified in 2017 include the following:

(a) As the result of the issuance of the senior secured second lien notes, the Company has certain additional financial covenants that it is required to meet on a scheduled basis (see "Liquidity and Capital Resources"). In the event the Company breaches one of these covenants, the amounts payable on the notes as well as the senior credit facilities may become immediately due.

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 nine months ended September 30, 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, 2018 INITIAL GUIDANCE AND LONG-TERM STRATEGIC PLAN

	2017 Guidance				2018 Initial
	Initial Guidance	Q1 Update	Q2 Update	Q3 Update	Guidance
Production (boe/d)					
Annual average	10,000 – 11,000	10,000 – 11,000	10,000 – 11,000	10,100	11,000 – 12,000
Cash flow from operating activities (1) ($millions)	65 – 70	55 - 60	52 – 57	55 – 60	50 - 55
Adjusted funds flow (2) ($millions)	65 – 70	55 - 60	52 – 57	55 – 60	50 - 55
Capital expenditures ($millions)	200	185 - 190	195 – 200	195 – 200	60 - 65
Year-end debt ($millions)	135 - 140	130 - 135	140 – 145	135 – 140	145 - 155
Pricing Assumptions (annual average)					
Crude oil - WTI	US $54.50	US $52.75	US $49.50	US $49.85	US $52.00
Light/heavy differential	US $14.75	US $13.55	US $11.90	US $11.90	US $14.50
Foreign Exchange (Cdn$ to US$)	0.75	0.75	0.77	0.78	0.80

(1) Cash flow from operating activities is a GAAP measure and has a standardized meaning prescribed by Canadian GAAP.
(2) Adjusted funds flow is a non-GAAP measure. Adjusted funds flow 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. See non-GAAP financial measures.

Our plan for the remainder of 2017 is unchanged from our previous guidance update. We are still planning to spend between $195 and $200 million on capital projects with the focus being the expansion of the Onion Lake thermal project.

The capital program will be funded from a combination of our anticipated adjusted funds flow, proceeds from the issuance of the $75 million senior secured second lien notes and our undrawn senior credit facilities. Adjusted funds flow is expected to be between $55 and $60 million, up from our previous guidance of $52 to $57 million. The increase in adjusted funds flow is primarily attributable to higher forecast oil prices than what we used in previous guidance updates. For the remainder of the year we have assumed a WTI oil price of US$51.00, heavy oil differential of US$12.00 and a US$ to Cdn$ exchange rate of $0.81. Year-end 2017 debt levels are anticipated to be between $135 and $140 million, down from our previous guidance of $140 and $145 million. The decrease in year-end debt levels reflects an increase in forecasted adjusted funds flow for the remainder of the year.

We anticipate oil and gas production to average approximately 10,100 boe/d in 2017, which is within the range from our previous guidance.

2018 Initial Guidance
Capital spending in 2018 is expected to be between $60 and $65 million. The focus at the beginning of 2018 will be on completing construction of phase 2 of the Onion Lake thermal project. We expect to complete construction and initiate steam injection in late Q1 2018. For the remainder of 2018, we plan to resume drilling on some of our conventional heavy oil projects (approximately 20 wells), commence drilling a sustaining well pad for phase 1 of the Onion Lake thermal project and undertaking additional delineation drilling on our Blackrod lands.

We are planning to fund a significant portion of these capital costs with our anticipated adjusted funds flow, which we are budgeting to be between $50 and $55 million, supplemented with advances from our existing senior credit facilities. Year-end 2018 debt levels are anticipated to be between $145 and $155 million. Oil and gas production is expected to average between 11,000 and 12,000 boe/d in 2018. Exit production levels are expected to be approximately 14,000 boe/d.

Long-term Strategic Plan
The Company has reviewed its long-term strategic plan beyond 2018. Due to the prolonged period of low crude oil prices, the Company is planning to accelerate the expansion of the Onion Lake thermal project and defer the first phase of commercial development of the Blackrod SAGD project. In addition to crude oil prices, timing of the development of Blackrod is also dependent on anticipated capital and operating costs and the Company's ability to finance construction of the project. The Company's previous long-range plan had commercial development at Blackrod commencing within the next five years. Now, development of Blackrod will likely not begin until 2023 unless crude oil prices sufficiently improve or the Company finds a partner to participate in the development before then.

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources, including many factors beyond the control of the Company. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. See "Risk Factors – Operational Risks - Uncertainty of Reserve and Contingent Resource Estimates" and "Statement of Reserves Data and Other Oil and Gas Information – Significant Factors or Uncertainties" in the Company's Annual Information Form for the year ended December 31, 2016. Recognition of oil and gas reserves in Canada is based on definitions from the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). In order to be classified as reserves the COGE Handbook requires, among other things, significant spending on development of a project to commence within three years for proved reserves to be recognized, or within five years for probable reserves to be recognized.

As at December 31, 2016 the Company's independent reserves evaluator, Sproule Unconventional Limited (Sproule) assigned approximately 180 million barrels of probable undeveloped reserves (the Company's working interest, before royalties) with a net present value, discounted at 10%, of approximately $610 million to the Blackrod SAGD project. Due to the delay in the timing of development of Blackrod and the COGE Handbook guidelines on the recognition of reserves, this will result in the reclassification of these probable undeveloped reserves to contingent resources. Because the Company is accelerating the expansion at Onion Lake the Company may be in a position to recognize additional reserves at Onion Lake that are currently classified as contingent resource. Any changes to the Company's reserves will be reflected in the 2017 reserves evaluation prepared by Sproule, which is expected to be released in February 2018.

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", "believe", "plan", "planning", "planned", "project", "projects", "potential", "could", "estimate", "estimates", "estimated", "forecast", "forecasted", "likely", "expect", "expected", "may", "target", "impact", "new", "will", "should", "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, expected completion and initial steam date, peak production date and expected completion date of drilling for the second phase of the Onion Lake thermal project as discussed in the 2017 Significant Events section;
- Expectation that production at the Onion Lake thermal facility will return to full rates in the fourth quarter as discussed in the 2017 Significant Events section and in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales section;
- Improved Canadian dollar relative to the US dollar which will negatively impact our future revenues and cash flows as discussed in the Commodity Prices section;
- The estimated change in annualized adjusted funds flow for 2017 due to changes in key variables as discussed in the Commodity Prices section;
- Expectation that thermal transportation costs are expected to return to normal amounts in the fourth quarter as discussed in the Transportation Costs section;

- Expectation that thermal production costs per boe are expected to return to normal rates in the fourth quarter as discussed in the Production Costs section;
- Expected stock-based compensation expense for the remainder of 2017, 2018, 2019 and 2020 as discussed in the Stock-based Compensation section;
- The expected interest rate charged on our senior credit facilities for the remainder of 2017 as discussed in the Finance Costs section;
- Potential future asset impairments or reversals of impairments as discussed in the Depletion and Depreciation section;
- Expected cash taxes to be paid during the remainder of 2017 as discussed in the Income Taxes 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, 2018 Initial Guidance and Long-term Strategic Plan 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 that 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 November 7, 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		September 30, 2017		December 31, 2016
Assets					
Current assets					
Cash and cash equivalents	4	**$**	**24,102**	$	5,368
Trade and other receivables	5		**15,611**		13,391
Inventory			**245**		46
Prepaid expenses and deposits			**1,067**		705
Fair value of risk management assets	14		**1,425**		-
			42,450		19,510
Exploration and evaluation assets	6		**172,777**		170,737
Property, plant and equipment	7		**630,719**		542,157
		$	**845,946**	$	732,404
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	8	**$**	**48,657**	$	17,950
Current portion of decommissioning liabilities	9		**400**		644
Current portion of deferred consideration	10		**412**		404
Fair value of risk management liabilities	14		**1,838**		5,507
			51,307		24,505
Fair value of risk management liabilities	14		**2,344**		452
Decommissioning liabilities	9		**70,844**		71,122
Deferred consideration	10		**14,145**		14,425
Long-term debt	11		**72,738**		-
			211,378		110,504
Shareholders' equity					
Share capital	12		**970,894**		970,513
Contributed surplus			**44,594**		42,994
Deficit			**(380,920)**		(391,607)
			634,568		621,900
		$	**845,946**	$	732,404

Commitments and contingencies (note 13)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Comprehensive Income (Loss)

(unaudited) **(Cdn$ in thousands, except for per share amounts)**	Note	**Three months ended September 30, 2017**	Three months ended September 30, 2016	**Nine months ended September 30, 2017**	Nine months ended September 30, 2016
Revenue					
Oil and gas sales		**$ 32,894**	$ 32,367	**$ 107,800**	$ 73,706
Deferred consideration	10	**78**	-	**272**	-
Royalties		**(4,490)**	(4,111)	**(15,229)**	(9,269)
Net oil and gas revenue		**28,482**	28,256	**92,843**	64,437
Gain (loss) on risk management contracts	14	**(6,643)**	1,599	**4,958**	608
		21,839	29,855	**97,801**	65,045
Expenses					
Production		**12,978**	11,590	**40,313**	32,246
Transportation		**1,837**	2,013	**6,661**	5,339
General and administrative		**1,543**	1,614	**6,144**	5,313
Depletion and depreciation	7	**9,568**	11,984	**31,275**	33,389
Finance costs	15	**728**	1,343	**2,027**	3,823
Stock-based compensation	12	**599**	767	**1,709**	2,608
Foreign currency exchange loss (gain)		**149**	(12)	**230**	40
		27,402	29,299	**88,359**	82,758
Other income					
Gain on disposition of properties		**-**	-	**1,110**	-
Interest income		**118**	-	**135**	2
		118	-	**1,245**	2
Net and comprehensive income (loss) for the period		**$ (5,445)**	$ 556	**$ 10,687**	$ (17,711)
Income (loss) per share					
Basic	12	**$ (0.02)**	$ 0.00	**$ 0.03**	$ (0.05)
Diluted	12	**$ (0.02)**	$ 0.00	**$ 0.03**	$ (0.05)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Nine months ended September 30, 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	-	-	10,687	10,687
Stock-based compensation	-	1,709	-	1,709
Shares issued on exercise of stock options	272	-	-	272
Transfer to share capital on exercise of stock options	109	(109)	-	-
Balance - September 30, 2017	**$ 970,894**	**$ 44,594**	**$ (380,920)**	**$ 634,568**

	Nine months ended September 30, 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	-	-	(17,711)	(17,711)
Stock-based compensation	-	2,608	-	2,608
Shares issued on exercise of stock options	6	-	-	6
Transfer to share capital on exercise of stock options	2	(2)	-	-
Balance - September 30, 2016	$ 970,142	$ 42,406	$ (389,390)	$ 623,158

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) (Cdn$ in thousands)	Note	**Three months ended September 30, 2017**	Three months ended September 30, 2016	**Nine months ended September 30, 2017**	Nine months ended September 30, 2016
Operating activities					
Net and comprehensive income (loss) for the period		**$ (5,445)**	$ 556	**$ 10,687**	$ (17,711)
Items not involving cash:					
Depletion and depreciation	7	**9,568**	11,984	**31,275**	33,389
Accretion of decommissioning liabilities	15	**434**	357	**1,211**	1,084
Amortization of debt issuance costs		**206**	-	**206**	-
Stock-based compensation	12	**599**	767	**1,709**	2,608
Foreign exchange loss		**37**	-	**11**	-
Deferred consideration	10	**(78)**	-	**(272)**	-
Unrealized loss (gain) on risk management contracts	14	**8,091**	538	**(3,202)**	9,607
Gain on disposition of properties		**-**	-	**(1,110)**	-
Decommissioning costs incurred	9	**(440)**	(38)	**(565)**	(554)
Changes in non-cash working capital	15	**(2,197)**	2,277	**691**	(1,011)
Cash flow from operating activities		**10,775**	16,441	**40,641**	27,412
Financing activities					
Proceeds on issue of common shares, net of costs	12	**11**	-	**272**	6
Proceeds on issue of senior secured second lien notes, net of debt issuance costs		**-**	-	**72,320**	-
Proceeds on issue of senior credit facilities		**-**	-	**40,000**	-
Repayment of senior credit facilities		**-**	(13,000)	**(40,000)**	(21,000)
Cash flow from (used in) financing activities		**11**	(13,000)	**72,592**	(20,994)
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(519)**	(9)	**(2,095)**	(936)
Capital expenditures - property, plant and equipment	7	**(58,073)**	(1,744)	**(123,287)**	(3,839)
Proceeds from disposition of properties		**-**	-	**3,421**	-
Changes in non-cash working capital	15	**28,356**	960	**27,240**	(455)
Cash flow used in investing activities		**(30,236)**	(793)	**(94,721)**	(5,230)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**111**	(12)	**222**	40
Increase (decrease) in cash and cash equivalents		**(19,339)**	2,636	**18,734**	1,228
Cash and cash equivalents, beginning of period		**43,441**	892	**5,368**	2,300
Cash and cash equivalents, end of period		**$ 24,102**	$ 3,528	**$ 24,102**	$ 3,528

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 and nine months ended September 30, 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 November 7, 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 continuing to evaluate the impact of IFRS 15 and currently expects that the standard will not have a material impact on the Company's consolidated financial statements, however; the Company is still evaluating the impact of IFRS 15 on deferred consideration. The Company is currently evaluating the enhanced disclosures requirements related to the disaggregation of revenues from contracts with customers, the Company's performance obligations and any significant judgements. The Company intends to adopt the new standard using the modified retrospective method at the date of adoption.

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 continuing to evaluate the impact of IFRS 9 and currently expects that the standard will not have a material impact on the Company's consolidated financial statements other than enhanced disclosure including any significant judgements.

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 identifying, gathering and analyzing contracts impacted by the adoption of the new standard, as well as evaluating the system requirements for implementation. The Company is continuing to evaluate the impact of adopting IFRS 16 on the Company's consolidated financial statements.

4. CASH AND CASH EQUIVALENTS

		September 30, 2017		December 31, 2016
Cash at financial institutions	**$**	**24,102**	$	5,368

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of September 30, 2017, US $2.3 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

		September 30, 2017		December 31, 2016
Trade accounts receivable	**$**	**13,812**	$	13,206
Receivables from joint operation partners		**445**		328
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**13,972**		13,249
Receivable from risk management contracts		**302**		48
Other receivables		**1,337**		94
Total trade and other receivables	**$**	**15,611**	$	13,391

Aging of trade and other receivables are as follows:

At September 30, 2017	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 13,812	$ -	$ -	$ -	$ 13,812
Receivables from joint operation partners	69	-	2	374	445
Allowance for doubtful accounts	-	-	-	(285)	(285)
Receivable from risk management contracts	302	-	-	-	302
Other receivables	1,243	-	-	94	1,337
Total trade and other receivables	$ 15,426	$ -	$ 2	$ 183	$ 15,611

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	2,095
Change in decommissioning provision	(55)
At September 30, 2017	$ 172,777

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. There were no impairment losses of exploration and evaluation assets during the nine months ended September 30, 2017 (2016 - $Nil).

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 nine months ended September 30, 2017, the Company capitalized net operating revenues totalling a loss of $0.1 million ($0.3 million loss during the nine months ended September 30, 2016) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the nine months ended September 30, 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	123,278	9	123,287
Change in decommissioning provision	(1,139)	-	(1,139)
Dispositions	(2,311)	-	(2,311)
At September 30, 2017	$ 1,333,809	$ 3,649	$ 1,337,458
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	31,169	106	31,275
At September 30, 2017	$ 704,000	$ 2,739	$ 706,739
Net book value			
December 31, 2016	$ 541,150	$ 1,007	$ 542,157
September 30, 2017	$ 629,809	$ 910	$ 630,719

During the nine months ended September 30, 2017, the Company capitalized borrowing costs of $1.9 million (2016 - $Nil) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the nine months ended September 30, 2017 (2016 - $Nil).

At September 30, 2017, the Company performed a review of each of its cash generating units ("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. There were no impairment losses or reversals of property, plant and equipment during the nine months ended September 30, 2017 (2016 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30, 2017	December 31, 2016
Trade payables and accrued liabilities	**$ 47,513**	$ 16,879
Payables to joint operation partners	**296**	275
Other payables	**848**	796
Total accounts payable and accrued liabilities	**$ 48,657**	$ 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 $76.5 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 2.3% to 2.5% (December 31, 2016 – 2.0% to 2.3%) based on expected settlement dates. 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:

		Nine months ended September 30, 2017		Year ended December 31, 2016
Decommissioning liability, beginning of the period	$	**71,766**	$	66,927
New liabilities recognized		**2,159**		103
Decommissioning costs incurred		**(565)**		(580)
Change in estimated costs of decommissioning		**-**		(2,813)
Change in inflation rate		**-**		6,864
Change in discount rate		**(3,327)**		(196)
Accretion expense		**1,211**		1,461
Decommissioning liability, end of the period		**71,244**		71,766
Less current portion of decommissioning liability		**(400)**		(644)
Non-current portion of decommissioning liability	$	**70,844**	$	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:

		Nine months ended September 30, 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		**(272)**		-
Deferred consideration, end of the period		**14,557**		14,829
Less current portion of deferred consideration		**(412)**		(404)
Non-current portion of deferred consideration	$	**14,145**	$	14,425

Significant Accounting Judgements and Estimates – Sale of a Royalty Interest

When the Company sells a royalty interest linked to production at a specific property, judgment is required in assessing the appropriate accounting treatment of the transaction on the closing date and in future periods. We consider the specific terms of each arrangement to determine whether we have disposed of an interest in the reserves of the respective property. This assessment considers whether the counterparty is entitled to and the associated risks and rewards attributable to them over the life of the property including the contractual terms and implicit obligations related to production over the life of the property, the holder of the royalty having the option of either being paid in cash or in kind and the associated commitments, if any, to develop future expansions or projects at the property.

In the fourth quarter of 2016, the Company sold a royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay an approximate 1.75% royalty on production from substantially all of its Onion Lake lands. The Company applied judgment in concluding that the proceeds for the sale of the royalty interest on the Onion Lake properties comprised two components: (1) a payment for partial disposal of an interest in property, plant and equipment; and (2) an upfront payment received for future extraction services that will generate future royalties.

The Company used discounted future cash flows of future development and operating costs multiplied by the approximate 1.75% royalty rate to derive the upfront payment received for future extraction services of $14.8 million, which is being accounted for as deferred consideration and recognized as revenue over the reserve life at Onion Lake (as this is estimated to approximate the efforts we incur towards the extraction performance obligation). The calculation of the upfront payment received for future extraction services included estimated future development costs, estimated future operating costs and a discount rate applied to the future cash flows in determining the amount of deferred consideration based on management's judgment.

The remaining proceeds of $40.2 million were compared to the carrying value attributable to the partial disposal of property, plant and equipment, which resulted in no gain or loss recognized on the disposition. The Company applied judgment in determining the carrying value of property, plant and equipment to be disposed, which was derived based on the proportion of proved and probable reserve value given up on the Company's Onion Lake properties.

11. LONG-TERM DEBT

		September 30, 2017		December 31, 2016
Senior credit facilities	**$**	**-**	$	-
8% senior secured second lien notes		**75,000**		-
Less: unamortized debt issuance costs		**(2,262)**		-
Total long-term debt	**$**	**72,738**	$	-

(a) Senior Credit Facilities

At September 30, 2017, the Company had senior credit facilities of $120 million, consisting of a $110 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 September 30, 2017, the Company had not drawn any amounts (December 31, 2016 – no amounts drawn) under these senior credit facilities and had letters of credit issued in the amount of $20,000 (December 31, 2016 - $20,000); leaving $120 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 any shortfall. The next scheduled Borrowing Base redetermination is to occur by November 30, 2017. The senior credit facilities have been provided on a revolving basis until May 27, 2018, at which time they may be extended at the lenders option. If the lenders elected not to renew the senior credit facilities, any amounts outstanding would convert to a term loan that would be due and payable in full by May 27, 2019.

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 senior 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.

(b) Senior Secured Second Lien Notes

On June 30, 2017, the Company issued $75 million senior secured second lien notes bearing an interest rate of 8%, payable quarterly in arrears, and due on June 30, 2020. The proceeds from the senior secured notes were made available in a single draw and amounts borrowed under the senior secured notes that are repaid or prepaid are not available for re-borrowing. The senior secured notes are secured by substantially all of the assets of the Company on a second priority basis, subordinate only to the senior credit facilities. The Company may redeem the senior secured second lien notes at any time at a price equal to par, plus a "make-whole" premium and any accrued interest. At September 30, 2017, the carrying value of the senior secured notes was $72.7 million, net of unamortized debt issuance costs.

(c) Covenants

The Company is subject to a number of financial covenants under the terms of the senior credit facilities and the senior secured second lien notes. The significant covenants under these debt instruments are summarized below.

(i) The Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital is defined as current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the senior 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 3.3:1 at September 30, 2017 (December 31, 2016 – 7.2:1).

(ii) The Company is limited to a maximum total debt to EBITDA ratio of 4.5:1 at the end of each fiscal quarter. The Company is also limited to a maximum senior credit facilities debt to EBITDA ratio of 3.5:1 at the end of each fiscal quarter on or before December 31, 2018. After December 31, 2018, the Company is limited to maximum senior credit facilities debt to EBITDA ratio of 3:1. Total debt is defined as the Company's total debt outstanding excluding accounts payable and accrued liabilities, decommissioning liabilities, deferred consideration and liabilities under risk management contracts at the end of each fiscal quarter. Senior credit facilities debt is any amounts drawn on the senior credit facilities plus any letters of credit outstanding. EBITDA is defined as the Company's net income for the trailing 12 month period before financing charges, income taxes, all non-cash items including depletion and depreciation, accretion, future taxes, stock-based compensation, unrealized gains or losses on risk management contracts and write down or reversal of impairment of assets, income or losses attributable to extraordinary and non-recurring gains or losses and gains or losses from asset sales. The Company had a total debt to EBITDA ratio of 1.3:1 and a senior credit facilities debt to EBITDA ratio of 0.0:1 at September 30, 2017.

(iii) The Borrowing Base under the senior credit facilities cannot exceed $240 million.

(iv) The Company will not, as of any asset coverage test date, permit the asset coverage ratio to be less than 1.5:1. Asset coverage ratio is defined as the discounted net present value of the Company's total proved reserves discounted at 10% compared to total debt. The asset coverage test date is defined as May 1 and November 1 of each fiscal year and each date on which a material acquisition or disposition is consummated.

(v) The Company is required as at the end of each of its fiscal quarters to have hedged at least 50% of its projected working interest production (net of royalties) for the forward looking 12 months and at least 20% of the next six months of projected production (months 13-18 forward) is required to be hedged.

(vi) The Company is restricted from paying cash dividends to shareholders under the terms and conditions of the credit facilities.

At September 30, 2017, the Company was in compliance with all debt covenants.

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	318,340	272
Transferred from contributed surplus on exercise of stock options	-	109
Balance as at September 30, 2017	336,267,235	$ 970,894

(c) Restricted Share Units ("RSUs") Outstanding

In 2017, the Board and shareholders approved 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 that 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. Currently, the Company intends to settle vested RSUs in common shares at the vesting date. During the first nine months of 2017, 1,000,000 RSUs were granted to officers and directors and 760,000 RSUs were granted to other eligible plan participants. The following table summarizes RSUs outstanding:

	Number of RSUs
Outstanding at December 31, 2016	-
Granted	1,760,000
Forfeited	(50,000)
Outstanding at September 30, 2017	1,710,000

The Company accounts for RSUs as equity based awards and the estimated fair value of the awards is determined at the time of the grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. During the nine months ended September 30, 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 $1.64 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	1,887,000	1.50
Exercised	(318,340)	0.86
Forfeited	(339,999)	1.78
Expired	(1,294,500)	3.86
Outstanding at September 30, 2017	26,860,496	1.68

Options outstanding and exercisable as at September 30, 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	10,884,496	0.84	2.77	6,910,047	0.84	2.72
1.51 – 3.00	15,626,000	2.23	1.77	13,980,667	2.31	1.45
3.01 – 3.87	350,000	3.23	0.11	350,000	3.23	0.11
	26,860,496	1.68	2.15	21,240,714	1.85	1.85

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the nine months ended September 30, 2017, 1,887,000 options were granted (2016 – 125,000) and during the three months ended September 30, 2017, 20,000 options were granted (2016 – 50,000). The fair value of these options was estimated using the following weighted average assumptions:

	Three months ended September 30		Nine months ended September 30	
Assumptions	**2017**	2016	**2017**	2016
Risk free interest rate (%)	**1.5**	0.5	**1.0**	0.6
Dividend yield (%)	**0.0**	0.0	**0.0**	0.0
Expected life (years)	**3.9**	3.8	**3.8**	3.7
Expected volatility (%)	**53.8**	55.8	**56.2**	55.1
Forfeiture rate (%)	**10.0**	10.8	**10.2**	11.3
Weighted average fair value of options	**$ 0.45**	$ 0.43	**$ 0.65**	$ 0.36

(e) Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Gross stock-based compensation related to options	**$ 323**	$ 767	**$ 1,108**	$ 2,656
Gross stock-based compensation related to RSUs	**276**	-	**627**	-
Total gross stock-based compensation	**599**	767	**1,735**	2,656
Recoveries from forfeitures related to options	**-**	-	**(23)**	(48)
Recoveries from forfeitures related to RSUs	**-**	-	**(3)**	-
Net stock-based compensation	**$ 599**	$ 767	**$ 1,709**	$ 2,608

(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 September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Net and comprehensive income (loss)	**$ (5,455)**	$ 556	**$ 10,687**	$ (17,711)
Weighted average number of common shares - basic	**336,266**	335,646	**336,217**	335,642
Dilutive effect:				
Outstanding options	**2,478**	2,313	**3,566**	-
Weighted average number of common shares - diluted	**338,744**	337,959	**339,783**	335,642
Basic income (loss) per share	**$ (0.02)**	$ 0.00	**$ 0.03**	$ (0.05)
Diluted income (loss) per share	**$ (0.02)**	$ 0.00	**$ 0.03**	$ (0.05)

For the nine months ended September 30, 2017, the Company used a weighted average market closing price of $1.31 per share to calculate the dilutive effect of stock options. For the nine months ended September 30, 2017, 16,480,470 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)	$ 213	$ 788	$ 579	$ 437	$ 421	$ -
Electrical service agreement (2)	294	585	119	119	119	1,868
Transportation service agreement (3)	34	135	135	33	-	-
Decommissioning liabilities (4)	79	428	346	8,919	1,634	65,101
Capital commitments (5)	6,090	5,000	5,000	-	-	-
Long-term debt (6)	-	-	-	75,000	-	-
Interest payments on long-term debt (6)	1,500	6,000	6,000	3,000	-	-
Total	$ 8,210	$ 12,936	$ 12,179	$ 87,508	$ 2,174	$ 66,969

(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 $76.5 million as at September 30, 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.

(6) The Company issued $75 million senior secured second lien notes bearing an interest rate of 8% payable quarterly in arrears and due on June 30, 2020.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt.

(a) Fair value of financial instruments

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

	September 30, 2017		December 31, 2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial assets				
Loans and receivables:				
Cash and cash equivalents	$ 24,102	$ 24,102	$ 5,368	$ 5,368
Trade and other receivables	$ 15,611	$ 15,611	$ 13,391	$ 13,391
Deposits	$ 200	$ 200	$ 142	$ 142
Financial liabilities at fair value through profit or loss:				
Fair value of risk management assets	$ 1,425	$ 1,425	$ -	$ -
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 48,657	$ 48,657	$ 17,950	$ 17,950
Long-term debt	$ 75,000	$ 75,000	$ -	$ -
Financial liabilities at fair value through profit or loss:				
Fair value of risk management liabilities	$ 4,182	$ 4,182	$ 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 value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. 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 September 30, 2017, the Company held $24.1 million in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 90% 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 September 30, 2017, 89% 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 nine months of 2017, the Company did not experience any collection issues with its marketers.

In the first nine months of 2017, the Company had four customers that 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 nine months 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 nine months 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 September 30, 2017, the Company had $120 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

The maturity dates for the Company’s undiscounted cash outflows related to financial liabilities are as follows:

	Total	**< 1year**	**1 – 5 Years**
Accounts payable and accrued liabilities	48,657	48,657	-
Risk management liabilities	4,182	1,838	2,344
Capital commitments	16,090	8,590	7,500
Long-term debt	75,000	-	75,000
Interest payments on long-term debt	16,500	4,500	12,000
Total	**160,429**	**63,585**	**96,844**

(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 senior credit facilities due to the floating interest rate charged on advances. For the nine months ended September 30, 2017, if interest rates had been one percent higher with all other variables held constant, after tax net income would have been approximately $57,000 lower. The remainder of the Company’s financial assets and liabilities are not exposed to interest rate risk. 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 September 30, 2017, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at September 30, 2017, the Company held US $2.3 million in cash and cash equivalents and US $0.3 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 nine months ended September 30, 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 September 30, 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% (2016 – 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 September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Realized gain on risk management contracts	**$ 1,448**	$ 2,137	**$ 1,756**	$ 10,215
Unrealized gain (loss) on risk management contracts	**(8,091)**	(538)	**3,202**	(9,607)
Gain (loss) on risk management contracts	**$ (6,643)**	$ 1,599	**$ 4,958**	$ 608

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2017:

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2017						
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap	$ 195
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 53.10/bbl	Swap	140
Oil	500 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 53.00/bbl	Swap	121
Oil	500 bbls/d	October 1 to	CDN$ WCS	CDN$ 52.75/bbl	Swap	125
Oil	500 bbls/d	October 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap	(9)
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap	(2)
Oil	1,000 bbls/d	October 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap	(72)
Oil	1,000 bbls/d	October 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call	(12)
2018						
Oil	2,000 bbls/d	January 1 to March 31	CDN$ WCS/WTI Differential	CDN$ 16.25/bbl	Swap	125
Oil	2,000 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 49.55/bbl	Swap	717
Oil	1,000 bbls/d	January 1 to June 30	US$ WTI	US$ 45.00/bbl to 57.75/bbl	Collar	(22)
Oil	1,500 bbls/d	January 1 to June 30	US$ WTI	US$ 40.00/bbl to 50.00/bbl	Collar	(1,531)
Oil	500 bbls/d	July 1 to September 30	US$ WTI	US$ 40.00/bbl to 58.00/bbl	Collar	(55)
Oil	500 bbls/d	July 1 to September 30	US$ WTI	US$ 45.00/bbl to 54.00/bbl	Collar	(75)
Oil	1,000 bbls/d	July 1 to September 30	US$ WTI	US$ 40.00/bbl to 60.00/bbl	Collar	(47)
Oil	1,000 bbls/d	July 1 to September 30	US$ WTI	US$ 45.00/bbl to 57.00/bbl	Collar	(11)
Oil	2,200 bbls/d	July 1 to December 31	US$ WTI	US$ 40.00/bbl to 51.00/bbl	Collar	(2,086)
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call	(69)
2019						
Oil	500 bbls/d	January 1 to March 31	US$ WTI	US$ 40.00/bbl to 60.00/bbl	Collar	(17)

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
Oil	500 bbls/d	January 1 to March 31	US$ WTI	US$ 43.25/bbl to 57.00/bbl	Collar	(22)
Oil	1,600 bbls/d	January 1 to March 31	US$ WTI	US$ 40.00/bbl to 58.25/bbl	Collar	(150)
Total						$ (2,757)
Current portion of fair value of contracts						$ (413)
Non-current portion of fair value of contracts						$ (2,344)

As at September 30, 2017, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $11.0 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 $12.8 million decrease in fair value of these contracts and decrease in income for the period.

15. SUPPLEMENTARY INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Cash interest paid	**$ 1,722**	**$** 986	**$ 2,516**	$ 2,739

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Gross interest and financing charges	**$ 1,722**	**$** 986	**$ 2,516**	$ 2,739
Capitalized interest and financing charges	**(1,634)**	-	**(1,906)**	-
Net interest and financing charges	**88**	986	**610**	2,739
Accretion of decommissioning liabilities	**434**	357	**1,211**	1,084
Amortization of debt issuance costs	**206**	-	**206**	-
Finance costs	**$ 728**	**$** 1,343	**$ 2,027**	$ 3,823

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

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Changes in non-cash working capital				
Trade and other receivables	**$ (1,327)**	$ 1,437	**$ (2,220)**	$ (869)
Inventory	**(180)**	10	**(199)**	517
Prepaid expenses and deposits	**755**	657	**(362)**	(17)
Accounts payable and accrued liabilities	**26,911**	1,133	**30,712**	(1,097)
Changes in non-cash working capital	**$ 26,159**	$ 3,237	**$ 27,931**	$ (1,466)
Relating to:				
Operating activities	**$ (2,197)**	$ 2,277	**$ 691**	$ (1,011)
Investing activities	**$ 28,356**	$ 960	**$ 27,240**	$ (455)