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NEWS RELEASE **November 10, 2015**

BLACKPEARL ANNOUNCES THIRD QUARTER 2015 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, 2015.

Highlights include:

- At Onion Lake, we began producing oil in September from our thermal EOR project. Production is ramping-up and is currently in excess of 3,000 barrels of oil per day. Phase one of the project has a design capacity of 6,000 barrels of oil per day which we expect to achieve in the first half of 2016;
- At Blackrod, the pilot results from the second SAGD well pair continue to be positive; in Q3 2015 the well produced 552 barrels of oil per day with a steam oil ratio of 2.7;
- As a result of our cost reduction initiatives, we have reduced our operating and transportation costs, on a barrel of oil equivalent (boe) basis, by over 20% in 2015 compared to 2014;
- Oil and gas revenues in Q3 2015 were $20.8 million and funds flow from operations was $10.2 million. Year to date we have generated revenues of $74 million and funds from operations of $38 million;
- The decline in crude oil prices in 2015 were partially offset by realized gains on crude oil hedging contracts. In Q3 we realized gains of $8 million and year to date we have realized gains of $27 million;
- Capital spending was $8 million in Q3 2015 and $67 million for the first nine months of the year. Over 90% was spent on the thermal project at Onion Lake. We have reduced capital spending in other core areas due to low oil prices and our desire to maintain a strong financial position;
- Existing credit facilities were $150 million, with $97 million drawn as at September 30, 2015. The Company had net debt (bank debt less working capital) of $89 million at the end of Q3 2015;
- Production averaged 7,478 barrels of oil equivalent (boe) per day in the third quarter, a 19% decrease compared to Q3 2014 volumes. The decrease is attributed to shutting-in various high cost wells, no drilling activity in 2015 and the fact that the Onion Lake thermal project only started producing oil late in the quarter. Current production is in excess of 9,500 barrels of oil per day as a result of the continued ramp-up of thermal production at Onion Lake.

John Festival, President of BlackPearl commenting on Q3 2015 activities stated that “It was a challenging quarter for heavy oil producers as oil prices retreated back to the mid $40’s and heavy oil differentials widened. Our objective in this price environment is to remain financially disciplined and limit our capital spending to only our very best projects that are profitable with low oil prices. For us, this is the Onion Lake thermal project. We are very proud of the achievements that have occurred at Onion Lake in 2015. Firstly, we completed the project on time and within budget in the second quarter. The installed costs of around $35,000 per flowing barrel will be among the best in class in terms of capital efficiency. Then, we successfully commissioned the steam generation facilities and initiated steam injection in May. In the third quarter we reached a new milestone with the project when we achieved first oil production in September. Today, production from the project is over 3,000 barrels of oil per day and we anticipate reaching our target of 6,000 barrels of oil per day in the first half of 2016. Onion Lake thermal will become our lowest cost production. In the meantime, production from our other areas has declined due to limited sustaining capital but we felt it was particularly important to manage our balance sheet with these low oil prices. When oil prices recover we expect to put this production back online."

Financial and Operating Highlights

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Daily production / sales volumes				
Oil (bbl/d)	7,115	8,744	7,514	8,798
Natural gas (mcf/d)	2,178	3,024	2,495	2,222
Combined (boe/d) (1)	7,478	9,248	7,930	9,168
Product pricing ($) (before the effects of hedging transactions)				
Crude oil - per bbl	35.02	75.89	38.15	76.89
Natural gas - per mcf	2.88	3.97	2.69	4.49
Combined - per boe (1)	34.05	72.90	36.90	74.84
Netback ($/boe) (1) (2)				
Oil and gas sales	34.05	72.90	36.90	74.84
Realized gain (loss) on risk management contracts	12.99	(0.58)	13.47	(1.65)
Royalties	6.48	12.73	6.25	14.18
Transportation	0.97	2.06	1.09	2.03
Operating costs	20.04	26.05	20.84	25.28
	19.55	31.48	22.19	31.70
($000's, except per share amounts)				
Revenue				
Oil and gas revenue – gross	20,814	58,818	73,641	180,547
Net income (loss) for the period	5,402	7,013	(15,621)	10,571
Per share, basic and diluted	0.01	0.02	(0.05)	0.03
Funds flow from operations(3)	10,156	23,809	38,064	70,007
Capital expenditures	7,870	80,262	66,843	177,666
Working capital deficiency(surplus) (4)	(8,254)	29,543	(8,254)	29,543
Bank debt (4)	97,000	-	97,000	-
Net Debt (5)	88,746	29,543	88,746	29,543
Shares outstanding, end of period	335,638,226	335,638,226	335,638,226	335,638,226

(1) 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.

(2)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.

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

(4)Working capital excludes current portion of bank debt of $15 million.

(5)Net debt is a non-GAAP measure.

Property Review

Onion Lake

We completed construction of phase one of the Onion Lake thermal project during the second quarter and commenced steam injection in late May. After approximately three months of injecting steam and warming the reservoir we started converting the producer wells over to oil production. We converted the first well pad of seven producer wells in late August and started to bring the second well pad of six wells on production in October. No major issues with the wells or the facilities have been encountered during the start-up.

During the month of September the thermal project produced approximately 800 barrels of oil per day and is currently producing in excess of 3,000 barrels of oil per day. We expect production to continue to ramp-up and reach design production capacity of 6,000 barrels of oil per day in the first half of 2016.

Blackrod

At Blackrod, the second SAGD pilot well pair continues to perform well. During the third quarter, production averaged 552 barrels of oil per day with a steam oil ratio of 2.7. The well has cumulatively produced in excess of 200,000 barrels of oil. The successful results from our two well pair pilot reinforces our confidence that the SAGD process works well and the Blackrod lease is ready for commercial development.

In August, the original pilot well pair at Blackrod required maintenance capital and we elected to defer incurring these costs and shut the well pair in. We have gathered sufficient valuable technical information from operating this well over the last four years that it is unlikely we will put the well back on production until we initiate commercial operations at Blackrod.

There have been no new updates this quarter regarding the status of our 80,000 barrel per day commercial development application at Blackrod. Although the application process has been much slower than we expected there have been no major roadblocks as we move towards approval. We anticipate receiving regulatory approval later this year or early next year.

Mooney

Our primary focus at Mooney has been on our cost reduction initiatives in the field. As a result of these measures we have been able to reduce operating costs in the field from over $3 million a month to approximately $2 million per month. The reduction in operating costs is primarily due to a slowing of chemical injection rates in certain areas of the reservoir, reduced service rates and lower staff levels. We are continuing with design plans for the expansion of the ASP flood to the phase two lands but we are unlikely to proceed with this expansion until WTI oil prices increase above US$55 per barrel.

Production

Oil and gas production averaged 7,478 barrels of oil equivalent per day in the third quarter of 2015, a 19% decrease compared with the third quarter of 2014. The decrease in oil production reflects natural production declines, no new drilling activity in 2015, reduced workover activity, as well as, the Company’s decision to shut-in various high cost conventional wells at Onion Lake due to low oil prices.

Average Daily Sales Volume

	Three months ended September 30,		Nine months ended September 30,	
(boe/day)	2015	2014	2015	2014
Onion Lake - conventional	3,285	4,203	3,621	4,132
Onion Lake - thermal	251	-	85	-
Mooney	2,192	3,429	2,523	3,547
John Lake	967	1,025	1,000	1,053
Blackrod	583	478	534	332
Other	200	113	167	104
	7,478	9,248	7,930	9,168

Financial Results

Oil and gas revenues in Q3 2015 were $20.8 million, a decrease of 65% compared to the third quarter of 2014. The decrease in revenues is attributable to a 53% decrease in our average sales price and a 19% decrease in production volumes.

Our realized oil price (before the effects of risk management activities) in Q3 2015 was $35.02 per barrel compared to $75.89 per barrel in Q3 2014. The decrease in our realized wellhead price reflects significantly lower WTI reference oil prices in Q3 2015 compared with Q3 2014 (US$46.43/bbl vs US$97.17/bbl), partially offset by tighter heavy oil differentials (US$13.39/bbl vs US$20.24/bbl) and a significantly weaker Canadian dollar relative to the US dollar ($0.764 vs $0.918).

We have entered into various oil hedges to mitigate some of the negative impact of the low oil price environment in 2015. During the first nine months of 2015 we realized a gain of $27 million from our oil hedging program, which was the equivalent of adding $13.47 per barrel to our wellhead price. The following summarizes the hedging contracts we currently have outstanding:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
2015					
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/bbl	Swap
2016					
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 70.65/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.10/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)
2017					
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	USD$ WTI	USD$ 60.00/bbl	Sold Call

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect on December 31, 2015 to exercise the option to enter into the oil swap.

Operating costs in Q3 2014 were $12.2 million, or $20.04 per boe, a 42% decrease from Q3 2014. The decrease in operating costs in 2015 is attributable to decreased production volumes as well as our continuing efforts to reduce and optimize operating costs in all our producing areas.

Reduced revenue, partially offset by lower royalties, transportation costs and operating costs resulted in a 57% decrease in funds flow from operations in Q3 2015 to $10.2 million compared to $23.8 million for the same period in 2014.

Bank debt as at September 30, 2015 was $97 million. Net debt (bank debt less working capital) was $89 million). The total credit facilities available to the Company are currently $150 million. The lenders next review of these facilities will be completed by November 30, 2015.

The 2015 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).

Guidance

Our plans for the remainder of 2015 are relatively unchanged from our Q2 and Q1 2015 guidance update. We are still planning to spend $70 to $75 million ($67 million spent as of September 30, 2015) on capital projects in 2015 with the major focus being the construction of the first phase of the Onion Lake thermal EOR project which was completed during the second quarter. Planned expansion of the ASP flood at Mooney and conventional heavy oil drilling at Onion Lake and John Lake have been deferred due to the current low oil price environment and our desire to maintain a strong balance sheet.

The capital program to September 30, 2015 has largely been funded by funds flow from operations and advances under the credit facilities. Fourth quarter 2015 capital expenditures, which are planned to be between $5 and $8 million, are expected to be funded from funds flow from operations. Funds flow for the year is expected to be between $45 and $50 million, up from our Q2 guidance of $40 to $45 million and year-end 2015 debt levels are anticipated to be between $95 and $100 million, down from our Q2 guidance of $100 to $105 million. The increase in funds flow from operations and lower year-end debt levels reflects higher realized risk management gains and lower operating costs as a result of the cost reduction initiatives we undertook during the first nine months of the year. We anticipate oil and gas production to average between 8,000 and 8,500 boe/d in 2015, which is in line with our previous quarterly updates.

Non-GAAP Measures

Throughout this news release, the Company uses terms "funds flow from operations", "netback" and "net debt". These terms do not have standardized meanings as prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other issuers. These terms are used by the Company to analyze operating performance, leverage and liquidity and to provide shareholders and investors with additional information to measure the Company's performance and efficiency and its ability to fund a portion of its future activities and to service any long-term debt. "Funds flow from operations" represents cash flow from operating activities (the closest GAAP measure) expressed before decommissioning costs incurred and changes in non-cash working capital. "Netback" is calculated as oil and gas revenues less royalties, production costs, transportation costs and realized gains/losses on risk management contracts, divided by total production for the period on a boe basis. “Net debt” represents long term debt less working capital.

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, but without limiting the foregoing, this report contains forward-looking statements pertaining to our business plans and strategies; expectation of reaching peak production rates of 6,000 barrels of oil per day at our Onion Lake thermal EOR project in the first half of 2016; the expectation that thermal production at Onion Lake will be our lowest cost production; the expected timing to receive regulatory approval for our commercial development application at Blackrod; the expectation of expanding the Mooney ASP flood when oil prices reach US$60 a barrel and all information included in the “Guidance” section of this release.

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

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

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

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The information in this release is subject to the disclosure requirements of BlackPearl Resources Inc. under the Swedish Securities Market Act and/or the Swedish Financial Instruments Trading Act. This information was publicly communicated on November 10, 2015 at 3:30 p.m. Mountain Time.

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three and nine months ended September 30, 2015. These results are being compared with the three and nine months ended September 30, 2014. 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, 2015, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2014.

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	Comprehensive income 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		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "funds flow from operations per share - basic", "funds flow from operations per share – diluted", "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. These terms are used by the Company to analyze operating performance, leverage and liquidity and to provide shareholders and investors with additional information to measure the Company's performance and efficiency and its ability to fund a portion of its future activities and to service any long-term debt. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. Operating netback is calculated as oil and gas revenues less royalties, production costs and transportation costs, divided by total production for the period on a boe basis. Net debt is calculated as long-term debt plus working capital for the period ended. Working capital excludes the current portion of long-term debt.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flows from operating activities", the nearest GAAP measure. "Funds flow from operations" excludes decommissioning costs incurred and changes in non-cash working capital related to operations, while the GAAP measurement, "Cash flows from operating activities" includes these items. Funds flow from operations per share – basic & diluted is calculated as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations divided by the weighted average number of common shares outstanding for the period.

	2015			2014	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2015**	2014
Cash flows from operating activities[(1)]	**14,216**	12,100	23,849	25,587	**50,165**	68,146
Add (deduct):						
Decommissioning costs incurred	**117**	17	245	213	**379**	700
Changes in non-cash working capital related to operations	**(4,177)**	2,851	(11,154)	(1,991)	**(12,480)**	1,161
Funds flow from operations[(2)]	**10,156**	14,968	12,940	23,809	**38,064**	70,007

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

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

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 10, 2015.

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 market 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 EOR project with the first phase constructed and currently being commissioned;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property, in the exploration and evaluation phase, located in the Athabasca oil sands region using the SAGD recovery process. The Company is currently operating a pilot project on this property.

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.

2015 SIGNIFICANT EVENTS

- Crude oil prices were significantly lower in the first nine months of 2015, with WTI oil prices averaging US$51.00 per bbl during the first nine months of 2015 compared to US$99.61 per bbl barrel during the same period in 2014.

- Capital expenditures during the first nine months of 2015 were $66.8 million, with approximately $61.2 million related to the construction of the first phase of the Onion Lake thermal EOR project and pre-commercial first phase Onion Lake thermal EOR operations, $2.9 million spent at Blackrod related to continued capitalization of net revenues from operating the Blackrod pilot and other capital costs and $2.7 million spent in other areas.

- Oil and gas sales during the first nine months of 2015 were $73.6 million and funds flow from operations (non-GAAP measure) was $38.1 million. For the nine months ended September 30, 2015, the Company incurred a net loss of $15.6 million.

- The decline in crude oil prices in 2015 were partially offset by realized gains on crude oil hedging contracts. During the first nine months of 2015 we had realized gains of $27 million from these contracts.

- The Company did not undertake any equity issuances and no common shares were issued pursuant to the exercise of stock options during the first nine months of 2015.

- At September 30, 2015, BlackPearl had working capital of $8.3 million (excluding the current portion of long-term debt) and $97 million in bank debt, leaving $53 million available to be drawn under the Company's existing credit facilities.

- During the second quarter of 2015, construction was completed and initial steam injection occurred at the first phase of the Onion Lake thermal EOR project. The first phase of the project was designed for oil production of approximately 6,000 bbls/d. We expect to reach this production rate in the first half of 2016.

- Effective October 1, 2015, the Company commenced commercial production at the first phase of the Onion Lake thermal EOR project and related revenue and expenses will be included in the financial and operating results as of that date. Prior to October 1, 2015, all expenses, net of pre-commercial test production revenue, from the first phase of the Onion Lake thermal EOR project were capitalized. Production from the first phase of the Onion Lake thermal EOR project is currently in excess of 3,000 bbls/d.

SELECTED QUARTERLY INFORMATION

	2015			2014				2013
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31
Production (boe/d) [(1)(2)]	**7,478**	**8,051**	**8,269**	9,639	9,248	8,897	9,363	10,454
Oil and gas sales	**20,814**	**30,712**	**22,115**	47,798	58,818	62,174	59,555	54,072
Oil sales ($/bbl)	**35.02**	**47.52**	**32.05**	59.34	75.89	81.82	73.23	58.44
Gas sales ($/mcf)	**2.88**	**2.61**	**2.63**	3.39	3.97	4.61	5.41	3.50
Oil and gas sales ($/boe)	**34.05**	**45.37**	**31.25**	57.00	72.90	79.53	72.30	57.67
Production costs	**12,248**	**13,445**	**15,905**	21,066	21,021	20,291	19,673	18,420
Production costs ($/boe)	**20.04**	**19.86**	**22.48**	25.12	26.05	25.96	23.88	19.65
Realized gain (loss) on risk management contracts	**7,940**	**5,245**	**13,708**	5,846	(468)	(2,842)	(666)	-
Unrealized gain (loss) on risk management contracts	**11,826**	**(13,533)**	**(11,374)**	20,697	4,961	271	(5,301)	-
Net income (loss)	**5,402**	**(10,079)**	**(10,944)**	16,254	7,013	4,684	(1,126)	226
Per share, basic and diluted ($)	**0.01**	**(0.03)**	**(0.03)**	0.05	0.02	0.01	0.00	0.00
Capital expenditures	**7,870**	**15,992**	**42,981**	57,700	80,262	48,044	49,360	22,749
Funds flow from operations [(3)]	**10,156**	**14,968**	**12,940**	19,716	23,809	23,161	23,037	20,735
Per share, basic and diluted ($)	**0.03**	**0.04**	**0.04**	0.06	0.07	0.07	0.08	0.07
Long-term debt [(4)]	**97,000**	**94,000**	**78,000**	29,000	-	-	-	-

	2015			2014				2013
($000s, except where noted)	**Sep 30**	**Jun 30**	**Mar 31**	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31
Total assets (end of period)	**861,107**	**864,926**	**866,018**	837,773	785,538	765,233	747,763	652,216
Shares outstanding (000s)	**335,638**	**335,638**	**335,638**	335,638	335,638	335,638	328,398	300,425
Weighted average shares outstanding (000s)								
Basic	**335,638**	**335,638**	**335,638**	335,638	335,638	334,817	304,841	298,843
Diluted	**335,638**	**335,638**	**335,638**	335,638	335,638	335,244	305,874	300,768

(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) Includes pre-commercial test production from the first phase of the Onion Lake thermal EOR project. All sales and expenses from pre-commercial test production from the first phase of the Onion Lake thermal EOR project are being recorded as an adjustment to the capitalized costs of the project. Effective October 1, 2015, the first phase of the Onion Lake thermal EOR project commenced commercial production and all revenues and expenses associated with the project as of that date will be reported in the operating results of the Company.

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

(4) Includes current portion of long-term debt.

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 costs increased in 2014 as the Company began to expense all costs related to Phase 1 of the ASP flood at Mooney. During 2013 polymer and injection costs related to Phase 1 of the ASP flood at Mooney were expensed; however, all other chemical costs were still being capitalized.

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		2015			2014			
	2015	2014	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices									
West Texas Intermediate (WTI) (US$/bbl)	51.00	99.61	46.43	57.94	48.63	73.15	97.17	102.99	98.68
Western Canadian Select (WCS) (Cdn$/bbl)	47.44	85.87	43.27	56.95	42.11	66.73	83.80	90.42	83.39
Differential – WCS/WTI (US$/bbl)	13.35	21.15	13.39	11.62	14.71	14.39	20.24	20.08	23.11
Differential - WCS/WTI (%)	26.2%	21.2%	28.8%	20.1%	30.2%	19.7%	20.8%	19.5%	23.4%
Average Natural Gas Prices									
AECO gas (Cdn$/GJ)	2.62	4.56	2.75	2.52	2.61	3.41	3.81	4.71	4.91
Average Foreign Exchange (US$ per Cdn$1)	0.794	0.914	0.764	0.813	0.806	0.881	0.918	0.917	0.906

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

Crude oil prices weakened during the third quarter of 2015 and remain significantly lower than the comparable periods in 2014. WTI oil prices averaged US$46.43 per bbl in the third quarter of 2015 compared to US$57.94 per bbl in the second quarter of 2015 and US$97.17 per bbl in the third quarter of 2014. For the first nine months of 2015 WTI oil prices averaged US$51.00 per bbl, down 49% from US$99.61 per bbl in the same period in 2014. The decrease in 2015 has been primarily attributed to a demand/supply imbalance as a result of rising global oil production, particularly increases in shale production in the US, a slowdown in demand due to weaker global economic conditions, a strong US dollar, increased inventory levels and geopolitical events in various oil producing areas. The extended period of low oil prices has resulted in significantly lower capital spending in the oil sector. This reduced capital investment is beginning to impact production levels, particularly in North America, which over time is expected to improve the current demand/supply imbalance.

Generally, heavy oil differentials (WTI prices compared to WCS prices) have improved in 2015. For the nine months ended September 30, 2015 the differential averaged US$13.35 per bbl compared to US$21.15 per bbl for the first nine months in 2014. Increased refining capacity and transportation capacity has contributed to the tighter differential in 2015. The differential in Q3 2015 widened to US$13.39 per bbl compared to US$11.62 per bbl in the second quarter. The wider differential in Q3 2015 has been attributed to planned and unplanned refinery maintenance as well as increased heavy oil supply as several producer's projects in Western Canada that were shut down or curtailed as a result of forest fires earlier in the summer came back on production.

Natural gas prices decreased during the first nine months of 2015 averaging $2.62/GJ compared to $4.56/GJ in the same period in 2014. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current oil and gas sales. However, we do consume gas in our Blackrod pilot operations and as we commence operations on the first phase of our Onion Lake thermal EOR project the cost of gas will have a significant impact on our cost structure.

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 US benchmark prices. The Canadian dollar weakened against the US dollar in 2015 which has had a positive impact on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.79 during the first nine months of 2015 compared to Cdn$1 = US$0.91 in the same period in 2014.

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

Estimated change in annualized funds from operations for 2015 (1)		
Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	746
Realized crude oil price (Cdn$/bbl)	1.00	998
US $ to Canadian $ exchange rate	0.01	479

(1) This analysis uses current royalty rates, assumes annualized estimated average production of 8,350 boe per day, no changes in working capital and includes the impact of realized risk management contracts.

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

	2015			2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Daily production/sales volumes [1]						
Oil (bbls/d)	**6,281**	6,937	7,479	8,266	**6,895**	8,466
Natural gas (Mcf/d)	**2,178**	3,004	2,303	3,024	**2,495**	2,222
Combined (boe/d)	**6,644**	7,438	7,863	8,770	**7,311**	8,836
Bitumen – Blackrod (bbls/d) [2]	**583**	613	406	478	**534**	332
Oil – Onion Lake thermal (bbls/d)[3]	**251**	-	-	-	**85**	-
Total production (boe/d)	**7,478**	8,051	8,269	9,248	**7,930**	9,168
Product pricing (excluding risk management activities) [2] [3]						
Oil ($/bbl)	**35.02**	47.52	32.05	75.89	**38.15**	76.89
Natural gas ($/Mcf)	**2.88**	2.61	2.63	3.97	**2.69**	4.49
Combined ($/boe)	**34.05**	45.37	31.25	72.90	**36.90**	74.84
Sales ($000s) [2] [3]						
Oil and gas sales – gross	**20,814**	30,712	22,115	58,818	**73,641**	180,547
Royalties	**(3,963)**	(4,426)	(4,089)	(10,273)	**(12,478)**	(34,215)
Oil and gas sales – net	**16,851**	26,286	18,026	48,545	**61,163**	146,332

(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) All sales and expenses from the pre-commercial test production from the first phase of the Onion Lake thermal EOR project are being recorded as an adjustment to the capitalized costs of the project. Effective October 1, 2015, the first phase of the Onion Lake thermal EOR project commenced commercial production and all revenues and expenses associated with the project as of that date will be reported in the operating results of the Company.

Oil and natural gas sales decreased 65% in the third quarter of 2015 to $20.8 million from $58.8 million in the same period in 2014. The decrease in oil and gas sales is attributable to a 53% decrease in average sales prices received in the third quarter of 2015 compared to the same period in 2014 and a 19% decrease in production (on a boe basis).

Significantly lower WTI crude oil prices partially offset by tighter heavy oil differentials and a weaker Canadian dollar relative to the US dollar contributed to a decrease in our realized crude oil sales price in the third quarter of 2015. Our average oil wellhead sales price, prior to the impact of risk management activities, in the third quarter of 2015 was $35.02 per bbl compared with $75.89 per bbl in the same period in 2014.

The decrease in oil and gas production during the first nine months of 2015 is primarily attributable to natural declines, selectively shutting-in uneconomic wells during this period of low oil prices and reduced capital re-investment in our conventional oil and gas program. In order to manage our financial flexibility we elected to reduce capital spending and no new drilling activity has been undertaken in 2015.

Production growth during the next few quarters is expected to come from the recently completed first phase of our Onion Lake thermal EOR project. Production from the thermal project continues to ramp-up and is currently producing in excess of 3,000 barrels of oil per day. We anticipate production from this project to reach its 6,000 barrel per day design capacity in the first half of 2016.

Production from our non-thermal areas will likely continue to decrease as a result of natural declines and our intention to limit capital re-investment until oil prices improve.

On a boe basis, 95% of the Company's oil and natural gas production in the third quarter of 2015 was heavy oil or bitumen. The Onion Lake area accounted for 47% and the Mooney area accounted for 29% of total production in the third quarter of 2015.

	2015			2014	Nine months ended September 30	
Production by area (boe/d)	**Q3**	Q2	Q1	Q3	**2015**	2014
Onion Lake - conventional	**3,285**	3,624	3,959	4,203	**3,621**	4,132
Onion Lake - thermal	**251**	-	-	-	**85**	-
Mooney	**2,192**	2,588	2,797	3,429	**2,523**	3,547
John Lake	**967**	1,022	1,011	1,025	**1,000**	1,053
Other	**200**	204	96	113	**167**	104
Blackrod	**583**	613	406	478	**534**	332
Total production	**7,478**	8,051	8,269	9,248	**7,930**	9,168

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. All sales and expenses from the 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. Technical feasibility and commercial viability is established when reserves are recognized, regulatory approval has been obtained and commercial production of oil and gas has commenced. As of September 30, 2015, BlackPearl had not received regulatory approval for the commercial Blackrod project. During the third quarter of 2015, the pilot wells produced an average of 583 bbls/d of bitumen and the net revenues capitalized for the first nine months of 2015 were a loss of $1.8 million ($1.8 million loss in the first nine months of 2014).

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 mainly focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices and revenues. The Company's risk management trading 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.

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 mark-to-market values of our outstanding risk management contracts. The Company had a net gain of $19.8 million on its risk management contracts during the third quarter of 2015, consisting of a $7.9 million realized gain on the contracts and an unrealized gain of $11.8 million. The realized gain on risk management contracts was the equivalent of adding $12.99 per bbl to our wellhead price during the third quarter of 2015.

	2015			2014	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2015**	2014
Realized gain (loss) on risk management contracts	**7,940**	5,245	13,708	(468)	**26,893**	(3,976)
Per boe ($)	**12.99**	7.75	19.37	(0.58)	**13.47**	(1.65)
Unrealized gain (loss) on risk management contracts	**11,826**	(13,533)	(11,374)	4,961	**(13,081)**	(69)

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2015:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
2015					
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/bbl	Swap
2016					
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 70.65/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.10/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)
2017					
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	USD$ WTI	USD$ 60.00/bbl	Sold Call

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect on December 31, 2015 to exercise the option to enter into the oil swap.

Royalties

	2015			2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Royalties ($000s)	**3,963**	4,426	4,089	10,273	**12,478**	34,215
Per boe ($)	**6.48**	6.54	5.78	12.73	**6.25**	14.18
As a percentage of oil and gas sales	**19%**	14%	18%	17%	**17%**	19%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, to the Onion Lake Cree Nation. Royalties were $4.0 million in Q3 2015, down from $4.4 million in Q2 2015 and $10.3 million in Q3 2014. On a boe basis royalties decreased to $6.48 in the third quarter of 2015 from $12.73 in the same period in 2014. The decrease in royalties and royalties per boe reflects lower wellhead prices in 2015.

Royalties as a percentage of revenue increased to 19% of revenues in the third quarter of 2015 from 17% of revenues in the same period in 2014. The increase in royalties as a percentage of revenue in the third quarter of 2015 compared to the same period in 2014 is due to a decrease in the proportion of our production that is coming from the Mooney field (29% of third quarter production in 2015 compared to 37% of third quarter production in 2014), which has lower royalties due to the royalty incentive programs established for EOR projects in Alberta.

Going forward, royalties as a percentage of revenues are expected to drop (assuming no change in wellhead prices) as a result of the commencement of production from the first phase of the Onion Lake thermal EOR project. During the pre-payout period, royalties paid on revenues from this project are expected to be approximately 10%.

The new, recently elected Alberta government has established a panel to undertake a review of royalties applied to oil and gas production in the province. The panel is expected to provide their recommendations to the government by the end of the year. At this time, there is no indication what impact this royalty review with have on the Company. Approximately 49% of our production revenues in 2015 were derived in Alberta.

Transportation Costs

	2015			2014	Nine month ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Transportation costs ($000s)	**595**	800	781	1,665	**2,176**	4,892
Per boe ($)	**0.97**	1.18	1.10	2.06	**1.09**	2.03

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Changes in transportation costs, on a boe basis, are generally related to moving crude oil to different sales points to capture better marketing opportunities. Transportation costs decreased 64% in the third quarter of 2015 to $0.6 million from $1.7 million in the same period in 2014. The decrease in transportation costs is attributable, in part, to lower production volumes in the third quarter of 2015. The decrease in transportation costs is also attributable to several other factors. At Mooney, we currently ship close to 50% of our crude oil volumes by rail and in 2015 we have been delivering our oil to a new rail terminal much closer to our properties, which have significantly lowered our trucking costs. In addition, as a result of the downturn in activity levels in the energy sector we have been able to negotiate a reduction in truck rates with transport companies in all our major producing areas. Finally, throughout 2015, we have been shipping more of our Onion Lake volumes as emulsion rather than as clean marketable barrels. This results in lower clean oil transportation costs but it increases production expenses.

Production Costs

	2015			2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Production costs ($000s)	**12,248**	13,445	15,905	21,021	**41,598**	60,985
Per boe ($)	**20.04**	19.86	22.48	26.05	**20.84**	25.28

Production costs decreased 42% in the third quarter of 2015 to $12.2 million from $21.0 million in the same period in 2014. On a per boe basis, production costs decreased 23% in the third quarter of 2015 to $20.04 per boe from $26.05 per boe in the same period in 2014.

The decrease in production expenses in the third quarter of 2015 is attributable, in part, to decreased production volumes. In addition, due to the current low oil price environment the Company has been focusing on reducing production costs. This included negotiating lower service rates with various suppliers and contractors, deferring well servicing work, shutting-in specific wells in the Onion Lake area that are not economic at current oil prices and lowering chemical injection costs at Mooney.

Operating Netback ***[1]***

	2015			2014	Nine months ended September 30	
($/boe)	**Q3**	Q2	Q1	Q3	**2015**	2014
Revenues	**34.05**	45.37	31.25	72.90	**36.90**	74.84
Royalties	**6.48**	6.54	5.78	12.73	**6.25**	14.18
Transportation costs	**0.97**	1.18	1.10	2.06	**1.09**	2.03
Production costs	**20.04**	19.86	22.48	26.05	**20.84**	25.28
Operating netback before realized risk management contracts	**6.56**	17.79	1.89	32.06	**8.72**	33.35
Realized gain (loss) on risk management contracts	**12.99**	7.75	19.37	(0.58)	**13.47**	(1.65)
Operating netback after realized risk management contracts	**19.55**	25.54	21.26	31.48	**22.19**	31.70

(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.

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, excluding realized gains on risk management activities, decreased 80% in the third quarter of 2015 to $6.56 per boe from $32.06 per boe in the same period in 2014. The decrease is primarily attributable to the decrease in realized crude oil prices, partially offset by lower royalties and production costs.

General and Administrative Expenses (G&A)

	2015			2014	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2015**	2014
Gross G&A expense	**1,944**	2,279	2,499	2,317	**6,722**	8,170
Operator recoveries	**(244)**	(262)	(360)	(599)	**(866)**	(1,629)
Net G&A expense	**1,700**	2,017	2,139	1,718	**5,856**	6,541
Per boe ($)	**2.78**	2.98	3.02	2.13	**2.93**	2.71

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The decrease in gross G&A expenses in the third quarter of 2015 compared to the same period in 2014 is primarily attributable to lower third party consultants' costs as well as lower salary expenses. Lower operator recoveries in Q3 2015 compared to Q3 2014 reflects lower capital spending in 2015. Net G&A costs are comparable in Q3 2015 and Q3 2014.

Stock-Based Compensation

	2015			2014	Nine months ended September 30	
($000s, except per boe)	**Q3**	Q2	Q1	Q3	**2015**	2014
Gross stock-based compensation	**1,358**	1,328	1,628	1,539	**4,314**	3,960
Recoveries from forfeitures	**(10)**	(3)	(45)	(9)	**(58)**	(238)
Net stock-based compensation before capitalization	**1,348**	1,325	1,583	1,530	**4,256**	3,721
Capitalized stock-based compensation	**(47)**	(46)	(53)	(70)	**(146)**	(171)
Net stock-based compensation	**1,301**	1,279	1,530	1,460	**4,110**	3,551
Per boe ($)	**2.13**	1.89	2.16	1.81	**2.06**	1.47

Stock-based compensation costs are non-cash charges which reflect the estimated value of stock options 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 increase in stock-based compensation expense in the first nine months of 2015 compared to the same period in 2014 is primarily attributable to an increase in the number of options outstanding during the period. In the first nine months of 2015, 7,195,000 options were granted, 488,332 options were forfeited and 205,000 options expired. Based on stock options outstanding as at September 30, 2015, the Company has an unamortized stock option compensation expense of approximately $4.9 million, of which $1.3 million is expected to be expensed for the remainder of 2015, $2.8 million for 2016, $0.7 million in 2017 and $0.1 million in 2018.

During the first nine months of 2015, $146,000 of stock-based compensation costs were capitalized to property, plant and equipment related to options granted to contractors who work exclusively on the development activities at the Onion Lake thermal EOR project. The Company ceased capitalizing stock-based compensation on the Onion Lake thermal EOR project as of October 1, 2015, when the project commenced commercial production.

Finance Costs

	2015			2014	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2015**	2014
Gross interest & financing charges	**923**	1,062	583	191	**2,568**	837
Capitalized interest & financing charges	**(786)**	(760)	(520)	(173)	**(2,066)**	(380)
Net interest & financing charges	**137**	302	63	18	**502**	457
Accretion of decommissioning liabilities	**431**	428	417	392	**1,276**	1,151
Total finance costs	**568**	730	480	410	**1,778**	1,608

The increase in gross interest & financing charges in the third quarter of 2015 compared to the same period in 2014 is a result of higher weighted average debt levels in 2015, largely as a result of the increased capital spending on the construction of the first phase of the Onion Lake thermal EOR project. During the first nine months of 2015, $2.1 million of interest costs related to the construction of the Onion Lake thermal EOR project were capitalized. The Company ceased capitalizing interest costs on the Onion Lake thermal EOR project as of October 1, 2015, when the project commenced commercial production.

The average interest rate on advances under the Company's credit facilities was 3.4% during the first nine months of 2015. This does not include standby fees charged on unutilized amounts of the credit facilities. The interest rate charged on our debt is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate increased in the third quarter to 3.55% due, in part, to a higher debt to EBITDA ratio.

Depletion and Depreciation

	2015			2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Depletion and depreciation ($000s)	**12,360**	12,953	13,765	16,927	**39,078**	51,651
Per boe ($)	**20.22**	19.14	19.45	20.98	**19.58**	21.41

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 27% in the third quarter of 2015 to $12.4 million from $16.9 million in the same period in 2014. The decrease in depletion is primarily a result of lower production volumes in the third quarter of 2015.

On a boe basis, depletion and depreciation expense decreased to $20.22 per boe in the third quarter of 2015 as compared to $20.98 per boe in the same period in 2014. This decrease in depletion on a boe basis is primarily attributable to increased oil and gas reserves recognized in our third party reserves evaluation.

As of September 30, 2015, $276.9 million of expenditures included in property, plant and equipment that relate to the Onion Lake thermal EOR project are not subject to depletion. As of October 1, 2015, all expenditures related to the Onion Lake thermal EOR project are subject to depletion, the date when the project commenced commercial production. Exploration and evaluation assets of $169.3 million are also not subject to depletion.

There were no impairment provisions recorded for the nine months ended September 30, 2015 and 2014. However, further 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.

Interest Income

		2015		2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Interest income ($000s)	**4**	40	6	103	**50**	515

Interest income consists of interest earned on excess cash held by the Company. Interest income has decreased as a result of lower average cash balances maintained by the Company during the third quarter of 2015 compared to the same period in 2014.

Income Taxes

		2015		2014	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2015**	2014
Current income tax	**41**	29	30	19	**100**	63
Deferred income tax (recovery)	**2,443**	(3,133)	(3,265)	2,942	**(3,955)**	2,951
Total income tax (recovery)	**2,484**	(3,104)	(3,235)	2,961	**(3,855)**	3,014

BlackPearl did not pay cash income taxes in the first nine months of 2015 and does not expect to pay income taxes during the remainder of 2015 as we have sufficient tax pools to shelter expected income. The current income tax expense for 2015 is a result of capital tax. The Company recorded a deferred income tax expense of $2.4 million for the third quarter of 2015 as a result of taxable income during the period. The relatively high effective tax rate of 31% in Q3 2015 reflects expenses not deductible for tax purposes, principally stock-based compensation.

RESULTS FROM OPERATIONS

		2015		2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Net income (loss) ($000s)	**5,402**	(10,079)	(10,944)	7,013	**(15,621)**	10,571
Per share, basic ($)	**0.01**	(0.03)	(0.03)	0.02	**(0.05)**	0.03
Per share, diluted ($)	**0.01**	(0.03)	(0.03)	0.02	**(0.05)**	0.03

For the quarter ended September 30, 2015, the Company generated net income of $5.4 million compared to net income of $7.0 million in the same period in 2014. The decrease in net income in the third quarter of 2015 compared to the same period in 2014 is primarily a result of lower wellhead prices, partially offset by lower royalties and production costs and gains on risk management contracts.

		2015		2014	Nine months ended September 30	
	Q3	Q2	Q1	Q3	**2015**	2014
Funds flow from operations (1) ($000s)	**10,156**	14,968	12,940	23,809	**38,064**	70,007
Per share, basic ($)	**0.03**	0.04	0.04	0.07	**0.11**	0.22
Per share, diluted ($)	**0.03**	0.04	0.04	0.07	**0.11**	0.21

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

Funds flow from operations decreased 57% to $10.2 million during the third quarter of 2015 compared to $23.8 million in the same period in 2014. The decrease in funds flow in the third quarter of 2015 compared to the same period in 2014 is primarily a result of lower wellhead sales prices and lower production volumes in 2015, partially offset by the realized gain on risk management contracts and lower royalties and production costs.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**September 30, 2015**	December 31, 2014
Working capital deficiency (surplus) (1)	**(8,254)**	18,237
Supplemental loan due within one year	**15,000**	-
Revolving line of credit due beyond one year	**82,000**	29,000
Net debt (2)	**88,746**	47,237

(1) Working capital deficiency excludes the current portion of long-term debt.
(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.

The increase in net debt as at September 30, 2015 is primarily attributable to increased capital expenditures related to the construction of the first phase of the Onion Lake thermal EOR project.

In May, the Company completed its annual review and semi-annual borrowing base redetermination with the syndicate of lending institutions in its credit facility. Under the terms of the amended credit agreement with the lenders, the total credit facilities available to the Company remains at $150 million, consisting of $125 million syndicated revolving line of credit, a non-syndicated operating line of credit of $10 million and a $15 million supplemental loan facility.

At September 30, 2015, the Company had $97 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $53 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. The next scheduled Borrowing Base redetermination is to occur by November 30, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the revolving and operating lines of credit would be due and payable in full by May 27, 2017. Any outstanding advances under the supplemental loan facility are required to be repaid by May 28, 2016. The supplemental loan facility may also be repaid through proceeds of assets dispositions, capital raises, or advances under the available capacity of the revolving or operating lines of credit.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet (excluding any current amounts due on credit facilities). In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 4.2:1 at September 30, 2015 (December 31, 2014 – 2.3:1) and is in compliance with this covenant at September 30, 2015 and throughout the first nine months of 2015.

($000s, except working capital ratio)	**September 30, 2015**	December 31, 2014
Current assets per consolidated financial statements	**24,912**	43,651
Add: amount available to drawn on credit facilities	**52,980**	121,000
Less: current risk management assets	**(8,250)**	(20,628)
Current assets for working capital ratio	**69,642**	144,023
Current liabilities per consolidated financial statements	**31,658**	61,888
Less: current portion of long-term debt	**(15,000)**	-
Less: current risk management liabilities	**-**	-
Current liabilities for working capital ratio	**16,658**	61,888
Working capital ratio	**4.2**	2.3

The Company did not pay dividends on its common shares in the first nine months of 2015 and it does not anticipate paying dividends in the near term. In addition, the terms and conditions of the Company's existing credit facility agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending has decreased significantly in 2015 compared to 2014 as we adjust our activity levels to reflect a lower oil price environment and our desire to maintain financial flexibility. During the quarter ended September 30, 2015, capital spending was $7.9 million, a decrease from $80.3 million during the same period in 2014. The main components of the capital spending program during the third quarter was the completion of construction of the first phase of the Onion Lake thermal EOR project, capitalized net revenues relating to pre-commercial first phase of the Onion Lake thermal EOR operations and the continued capitalization of net revenues from operating the Blackrod pilot. No new drilling activity occurred during the third quarter of 2015. Throughout 2015 our primary focus has been on completing the first phase of the Onion Lake thermal EOR project. During the first nine months of 2015 total capital spending was $66.8 million, with over 90% related to the Onion Lake thermal EOR project.

		2015		2014	Nine months ended September 30	
($000s)	**Q3**	Q2	Q1	Q3	**2015**	2014
Land	**445**	194	146	233	**785**	708
Seismic	**74**	(132)	651	(36)	**593**	(117)
Drilling and completion	**1,340**	1,824	3,964	24,359	**7,128**	51,492
Equipment and facilities	**6,004**	14,067	38,145	55,699	**58,216**	123,932
Other	**7**	39	75	7	**121**	24
Total	**7,870**	15,992	42,981	80,262	**66,843**	176,039
Property acquisitions	**-**	-	-	-	**-**	1,627
Total capital expenditures	**7,870**	15,992	42,981	80,262	**66,843**	177,666
Property dispositions	**-**	-	-	-	**-**	-
Net capital expenditures	**7,870**	15,992	42,981	80,262	**66,843**	177,666

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, 2015. These obligations are expected to be funded from cash flows from operating activities and the Company's credit facilities.

($000s)	2015	2016	2017	2018	2019	Thereafter
Operating leases (1)	513	1,610	270	220	84	-
Electrical service agreement (2)	263	520	119	119	119	2,106
Transportation service agreement (3)	33	135	135	135	135	33
Decommissioning liabilities (4)	472	1,900	984	1,056	1,198	79,872
Long-term debt (5)	-	15,000	82,000	-	-	-
	1,281	19,165	83,508	1,530	1,536	82,011

(1) The Company has 12 months remaining on an operating lease for office space as at September 30, 2015. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional $3.2 million (including an estimate for operating costs) over the next 12 months. At September 30, 2015, no amounts were owed (2014 – no amounts owing).

(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 $85.5 million as at September 30, 2015. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(5) Based on the existing terms of the Company's revolving and operating lines of credit, the first possible mandatory repayment date may come in 2017 assuming these facilities are not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended. Any outstanding advances under the supplemental loan facility are required to be repaid by May 28, 2016; however, the supplemental loan facility may be repaid through proceeds of assets dispositions, capital raises, or advances under the available capacity of the revolving or operating lines of credit. At the present time it is the Company's intention to repay the advances under the supplemental loan facility from the unused available capacity under the revolving line of credit.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2015 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 are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

See the Company's unaudited consolidated financial statements for the three and nine months ended September 30, 2015 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, 2015 or 2014. 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 related-party transactions during the period ended September 30, 2015 or 2014.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at November 10, 2015, the Company had 335,638,226 common shares outstanding and 27,374,670 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at November 10, 2015, the Company had $97,000,000 drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $52,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of November 10, 2015, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The preparation of the interim consolidated financial statements requires management to make judgements and estimates that affect the reported amounts of assets, liabilities, sales, expenses and the disclosure of contingencies. Such judgements and estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. These judgements and estimates are subject to measurement uncertainty. Actual results could differ from and affect the results reported in the interim consolidated financial statements. 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, 2014. There have been no significant changes to the Company's critical accounting estimates as of September 30, 2015.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

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

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

RISKS AND UNCERTAINTIES

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2014 for a discussion of the risks and uncertainties associated with the Company activities. There have been no significant changes in these risks and uncertainties during the first nine months of 2015.

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal control over financial reporting ("ICFR") in the annual MD&A for the year ended December 31, 2014. There have been no changes to ICFR in the nine months ended September 30, 2015 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

2015 Guidance	Initial Guidance	Q1 Update	Q2 Update	Q3 Update
Production (boe/d)				
Annual average	8,000 – 9,000	8,000 – 9,000	8,000 – 9,000	8,000 – 8,500
Funds flow from operations ($millions)	15 – 20	25 - 30	40 - 45	45 - 50
Capital expenditures ($millions)	70 – 75	70 – 75	70 – 75	70 - 75
Year-end debt ($millions)	125 - 130	115 - 120	100 – 105	95 - 100
Pricing Assumptions (annual average)				
Crude oil - WTI	US$55.00	US$53.41	$US52.14	$US49.50
Light/heavy differential	US$15.00	US$14.18	$US12.85	$US13.65
Foreign Exchange (Cdn$ to US$)	0.85	0.81	0.79	0.79

Our plans for the remainder of 2015 are relatively unchanged from our Q2 and Q1 2015 guidance update. We are still planning to spend $70 to $75 million ($67 million spent as of September 30, 2015) on capital projects in 2015 with the major focus being the construction of the first phase of the Onion Lake thermal EOR project which was completed during the second quarter. Planned expansion of the ASP flood at Mooney and conventional heavy oil drilling at Onion Lake and John Lake have been deferred due to the current low oil price environment.

The capital program to September 30, 2015 has largely been funded by funds flow from operations and advances under the credit facilities. Fourth quarter 2015 capital expenditures, which are planned to be $8 million or less, are expected to be funded from funds flow from operations. Funds flow for the year is expected to be between $45 and $50 million, up from our Q2 guidance of $40 to $45 million and year-end 2015 debt levels are anticipated to be between $95 and $100 million, down from our Q2 guidance of $100 to $105 million. The increase in funds flow from operations and lower year-end debt levels reflects higher realized risk management gains and lower operating costs as a result of the cost reduction initiatives we undertook during the first nine months of the year. We anticipate oil and gas production to average between 8,000 and 8,500 boe/d in 2015, which is in line with our previous quarterly updates.

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”, “plans”, “planning”, “planned”, “could”, “continues”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expects”, “expected”, “may”, “intention”, “intended”, “indication”, “impact”, “new”, “will”, “in the event”, “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:

- Potential production levels and anticipated timing of peak oil production at the Onion Lake thermal EOR project as discussed in the 2015 Significant Events section;
- The expectation over time that production levels, particularly in North America, will decrease and improve the current demand/supply imbalance as discussed in the Commodity Prices section;
- Expected future gas prices and their impact on costs related to our thermal projects as discussed in the Commodity Prices section;
- The estimated change in annualized funds from operations for 2015 due to changes in key variables as discussed in the Commodity Prices section;

- Expected production growth and anticipated timing of peak oil production at the Onion Lake thermal EOR project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- The expected continued decrease in production from our non-thermal areas as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Expected royalties to be paid on revenues from the Onion Lake thermal EOR project as discussed in the Royalties section;
- Expectation that the royalty review panel as established by the Alberta government will provide their recommendations to the government by the end of the year as discussed in the Royalties section;
- Expected stock-based compensation expense for the remainder of 2015, 2016, 2017 and 2018 as discussed in the Stock-based Compensation section;
- Potential future asset impairments as discussed in the Depletion and Depreciation section;
- Expected cash taxes to be paid in 2015 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;
- The Company's expectation that the revolving and operating lines of credit will be extended at the next review as discussed in the Contractual Obligations and Commitments section;
- The Company's intention that the supplemental loan facility will be repaid from the unused capacity under the revolving line of credit as discussed in the Contractual Obligations and Commitments section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

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

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

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

Other Supplementary Information

1. List of directors and officers at November 10, 2015

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, 2015 is expected to be published on or before February 29, 2016.

3. Other Information

Address (Corporate head office):
BlackPearl Resources Inc.
700, 444 – 7 Avenue S.W.
Calgary, Alberta T2P 0X8
Canada
Telephone: +1.403.215.8313
Fax: +1.403.265.8324
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, 2015**	December 31, 2014
Assets			
Current assets			
Cash and cash equivalents	4	**$ 4,563**	$ 2,918
Trade and other receivables	5	**9,613**	18,467
Inventory		**339**	638
Prepaid expenses and deposits		**2,147**	1,000
Risk management assets	13	**8,250**	20,628
		24,912	43,651
Exploration and evaluation assets	6	**169,281**	166,344
Property, plant and equipment	7	**666,914**	627,778
		$ 861,107	$ 837,773
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	**$ 15,782**	$ 61,036
Current portion of long-term debt	10	**15,000**	-
Current portion of decommissioning liabilities	9	**876**	852
		31,658	61,888
Risk management liabilities	13	**703**	-
Decommissioning liabilities	9	**75,012**	59,831
Long-term debt	10	**82,000**	29,000
Deferred tax liabilities		**4,063**	8,018
		193,436	158,737
Shareholders' equity			
Share capital	11	**970,134**	970,134
Contributed surplus		**38,044**	33,788
Deficit		**(340,507)**	(324,886)
		667,671	679,036
		$ 861,107	$ 837,773

Commitments and contingencies (note 12)

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, 2015**	Three months ended September 30, 2014	**Nine months ended September 30, 2015**	Nine months ended September 30, 2014
Revenue					
Oil and gas sales		**$ 20,814**	$ 58,818	**$ 73,641**	$ 180,547
Royalties		**(3,963)**	(10,273)	**(12,478)**	(34,215)
Net oil and gas revenue		**16,851**	48,545	**61,163**	146,332
Gain (loss) on risk management contracts	13	**19,766**	4,493	**13,812**	(4,045)
		36,617	53,038	**74,975**	142,287
Expenses					
Production		**12,248**	21,021	**41,598**	60,985
Transportation		**595**	1,665	**2,176**	4,892
General and administrative		**1,700**	1,718	**5,856**	6,541
Depletion and depreciation	7	**12,360**	16,927	**39,078**	51,651
Finance costs	14	**568**	410	**1,778**	1,608
Stock-based compensation	11	**1,301**	1,460	**4,110**	3,551
Foreign currency exchange gain		**(37)**	(34)	**(95)**	(11)
		28,735	43,167	**94,501**	129,217
Other income					
Interest income		**4**	103	**50**	515
Income (loss) before income taxes		**7,886**	9,974	**(19,476)**	13,585
Income taxes					
Current income tax		**41**	19	**100**	63
Deferred income tax (recovery)		**2,443**	2,942	**(3,955)**	2,951
		2,484	2,961	**(3,855)**	3,014
Net and comprehensive income (loss) for the period		**$ 5,402**	$ 7,013	**$ (15,621)**	$ 10,571
Income (loss) per share					
Basic	11	**$ 0.01**	$ 0.02	**$ (0.05)**	$ 0.03
Diluted	11	**$ 0.01**	$ 0.02	**$ (0.05)**	$ 0.03

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, 2015			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2015	$ 970,134	$ 33,788	$ (324,886)	$ 679,036
Net and comprehensive loss for the period	-	-	(15,621)	(15,621)
Stock-based compensation	-	4,256	-	4,256
Balance - September 30, 2015	**$ 970,134**	**$ 38,044**	**$ (340,507)**	**$ 667,671**

	Nine months ended September 30, 2014			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2014	$ 881,949	$ 28,699	$ (351,711)	$ 558,937
Net and comprehensive income for the period	-	-	10,571	10,571
Stock-based compensation	-	3,721	-	3,721
Shares issued on equity offering	88,440	-	-	88,440
Share issue costs	(3,361)	-	-	(3,361)
Shares issued on exercise of stock options	2,046	-	-	2,046
Transfer to share capital on exercise of stock options	1,060	(1,060)	-	-
Balance - September 30, 2014	$ 970,134	$ 31,360	$ (341,140)	$ 660,354

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, 2015**	Three months ended September 30, 2014	**Nine months ended September 30, 2015**	Nine months ended September 30, 2014
Operating activities					
Net and comprehensive income (loss) for the period		**$ 5,402**	$ 7,013	**$ (15,621)**	$ 10,571
Items not involving cash:					
Depletion and depreciation	7	**12,360**	16,927	**39,078**	51,651
Accretion of decommissioning liabilities	14	**431**	392	**1,276**	1,151
Stock-based compensation	11	**1,301**	1,460	**4,110**	3,551
Foreign exchange loss		**45**	36	**95**	63
Deferred income tax (recovery)		**2,443**	2,942	**(3,955)**	2,951
Unrealized loss (gain) on risk management contracts	13	**(11,826)**	(4,961)	**13,081**	69
Decommissioning costs incurred	9	**(117)**	(213)	**(379)**	(700)
Changes in non-cash working capital	14	**4,177**	1,991	**12,480**	(1,161)
Cash flow from operating activities		**14,216**	25,587	**50,165**	68,146
Financing activities					
Proceeds on issue of common shares, net of costs		**-**	-	**-**	86,316
Increase in long-term debt	10	**3,000**	-	**68,000**	-
Cash flow from financing activities		**3,000**	-	**68,000**	86,316
Investing activities					
Capital expenditures - exploration and evaluation assets	6	**(415)**	(404)	**(2,962)**	(5,553)
Capital expenditures - property, plant and equipment	7	**(7,408)**	(79,571)	**(63,735)**	(171,725)
Changes in non-cash working capital	14	**(10,573)**	13,224	**(49,633)**	27,267
Cash flow used in investing activities		**(18,396)**	(66,751)	**(116,330)**	(150,011)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(82)**	(70)	**(190)**	(74)
Increase (decrease) in cash and cash equivalents		**(1,262)**	(41,234)	**1,645**	4,377
Cash and cash equivalents, beginning of period		**5,825**	54,013	**2,918**	8,402
Cash and cash equivalents, end of period		**$ 4,563**	$ 12,779	**$ 4,563**	$ 12,779

See accompanying notes to consolidated financial statements

1. GENERAL INFORMATION

BlackPearl Resources Inc. (collectively with its subsidiaries, 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 market under the symbol "PXXS". BlackPearl is incorporated and located in Canada. The address of its registered office is 700, 444 – 7th Avenue SW, Calgary, Alberta, T2P 0X8.

2. BASIS OF PREPARATION

These condensed unaudited interim consolidated financial statements for the three and nine months ended September 30, 2015 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, 2014. 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 10, 2015, 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, 2015 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, 2014 which have been prepared in accordance with IFRS as issued by the IASB.

3. SIGNIFICANT ACCOUNTING POLICIES

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

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

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

4. CASH AND CASH EQUIVALENTS

		September 30, 2015		December 31, 2014
Cash at financial institutions	**$**	**4,563**	$	2,918

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of September 30, 2015, US $1.1 million (2014 – US $1.5 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, 2015		December 31, 2014
Trade accounts receivable	**$**	**5,750**	$	12,249
Receivables from joint venture partners		**299**		309
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**5,764**		12,273
Royalty reimbursement from enhanced oil recovery incentive programs		**-**		1,038
Receivable from risk management contracts		**3,573**		4,059
Other receivables		**276**		1,097
Total trade and other receivables	**$**	**9,613**	$	18,467

Aging of trade accounts receivables are as follows:

		September 30, 2015		December 31, 2014
Current	**$**	**5,728**	$	12,232
31 to 60 days		**1**		9
61 to 90 days		**18**		8
Over 90 days		**3**		-
Trade accounts receivable	**$**	**5,750**	$	12,249

6. EXPLORATION AND EVALUATION ASSETS

At January 1, 2014	$ 161,408
Expenditures	7,250
Acquisition	1,627
Change in decommissioning provision	609
Transfers to property, plant & equipment	(4,550)
At December 31, 2014	166,344
Expenditures	2,962
Change in decommissioning provision	(25)
At September 30, 2015	$ 169,281

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During the first nine months of 2015, no assets were considered to be impaired.

The net operating revenues of the Blackrod SAGD pilot are being capitalized until transfer from exploration and evaluation assets to property, plant and equipment occurs. 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 reserves are recognized, regulatory approval has been obtained and the commercial production of oil and gas has commenced. During the nine months ended September 30, 2015 the Company capitalized net operating revenues totalling a loss of $1.8 million ($1.8 million loss in the first nine months of 2014). The Company did not capitalize any general and administrative costs related to exploration activities during the nine months ended September 30, 2015 (2014 - $Nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2014	$ 935,063	$ 3,442	$ 938,505
Expenditures	226,177	54	226,231
Capitalized stock-based compensation	258	-	258
Change in decommissioning provision	4,122	-	4,122
Transfers from exploration & evaluation assets	4,550	-	4,550
At December 31, 2014	1,170,170	3,496	1,173,666
Expenditures	63,726	9	63,735
Capitalized stock-based compensation	146	-	146
Change in decommissioning provision	14,333	-	14,333
At September 30, 2015	$ 1,248,375	$ 3,505	$ 1,251,880
Accumulated depletion and depreciation			
At January 1, 2014	$ 476,976	$ 2,118	$ 479,094
Depletion and depreciation	66,598	196	66,794
At December 31, 2014	543,574	2,314	545,888
Depletion and depreciation	38,949	129	39,078
At September 30, 2015	$ 582,523	$ 2,443	$ 584,966
Net book value			
December 31, 2014	$ 626,596	$ 1,182	$ 627,778
September 30, 2015	$ 665,852	$ 1,062	$ 666,914

During the nine months ended September 30, 2015, the Company capitalized borrowing costs of $2.1 million (2014 - $0.4 million) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the nine months ended September 30, 2015 (2014 - $Nil).

Property, plant and equipment at September 30, 2015 includes $276.9 million (December 31, 2014 - $201.7 million) of assets under construction pertaining to the Onion Lake Enhanced Oil Recovery (EOR) project that are not subject to depletion and depreciation until the project commences commercial operations.

There were no impairment losses or reversals of property, plant and equipment during the nine months ended September 30, 2015 (2014 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	September 30, 2015	December 31, 2014
Trade payables and accrued liabilities	**$ 15,277**	$ 60,065
Payables to joint arrangements	**347**	570
Other payables	**158**	401
Total accounts payable and accrued liabilities	**$ 15,782**	$ 61,036

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 liability is approximately $85.5 million (December 31, 2014 - $66.9 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 1.5% (December 31, 2014 – 2.0%) and discounted using a risk-free rate of 2.24% (December 31, 2014 - 2.49%). 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, 2015		Year Ended December 31, 2014
Decommissioning liability, beginning of period	**$**	**60,683**	$	55,384
New liabilities recognized		**15,067**		4,261
Liabilities acquired		**-**		470
Reduction in liabilities due to asset dispositions		**-**		(210)
Decommissioning costs incurred		**(379)**		(963)
Change in assumptions		**(759)**		209
Accretion expense		**1,276**		1,532
Decommissioning liability, end of period		**75,888**		60,683
Less current portion of decommissioning liability		**(876)**		(852)
Non-current portion of decommissioning liability	**$**	**75,012**	$	59,831

10. LONG-TERM DEBT

		September 30, 2015		December 31, 2014
Supplemental loan due within one year	**$**	**15,000**	$	-
Revolving line of credit due beyond one year		**82,000**		29,000
Long-term Debt	**$**	**97,000**	$	29,000

At September 30, 2015 the Company had credit facilities of $150 million, consisting of a $125 million syndicated revolving line of credit (December 31, 2014 - $140 million), a non-syndicated operating line of credit of $10 million (December 31, 2014 - $10 million) and a $15 million supplemental loan facility (December 31, 2014 - $Nil). At September 30, 2015, the Company had drawn $97 million under these credit facilities as well as letters of credit issued in the amount of $20,000. 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. The next scheduled Borrowing Base redetermination is to occur by November 30, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2016. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the revolving and operating lines of credit would be due and payable in full by May 27, 2017. Any outstanding advances under the supplemental loan facility are required to be repaid by May 28, 2016. The supplemental loan facility may also be repaid through proceeds of assets dispositions, capital raises, or advances under the available capacity of the revolving or operating lines of credit.

Pursuant to the lending 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 5.00%. Advances under the supplemental loan facility bear interest at 150 basis points (1.5%) above the rate applicable to advances under the revolving or operating line of credit. The lending agreement defines debt as any advances outstanding on the credit facilities plus any outstanding letters of credit/guarantee as per the Company's consolidated balance sheet. The lending agreement defines EBITDA as comprehensive income (loss) before income tax, financing charges, non-cash items deducted in determining comprehensive income (loss), unrealized gains or losses on risk management contracts and any income/losses attributable to assets acquired or disposed of when determining net comprehensive income (loss) for the period as indicated on the Company's consolidated statement of comprehensive income (loss). The Company also incurs a standby fee for undrawn amounts.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities (excluding any current amounts due on the credit facilities) from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 4.2:1 at September 30, 2015 (December 31, 2014 – 2.3:1) and is in compliance with this covenant at September 30, 2015.

11. 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, 2014	300,424,808	$ 881,949
Shares issued on equity offering	33,373,585	88,440
Share issue costs, net of tax benefits of $806	-	(3,361)
Shares issued on exercise of stock options	1,839,833	2,046
Transferred from contributed surplus on exercise of stock options	-	1,060
Balance as at December 31, 2014 and September 30, 2015	335,638,226	$ 970,134

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company and its subsidiaries. Under the Plan, the number of common shares to be reserved and authorized for issuance pursuant to options granted under the 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 majority of options vest at a rate of one third on each of the three anniversaries from the date of the grant. 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, 2014	14,606,499	3.26
Granted	12,124,500	2.30
Exercised	(1,839,833)	1.11
Forfeited	(1,343,498)	3.58
Expired	(2,631,333)	2.21
Outstanding at December 31, 2014	20,916,335	3.00
Granted	7,195,000	0.91
Forfeited	(488,332)	2.69
Expired	(205,000)	2.83
Outstanding at September 30, 2015	27,418,003	2.46

Options outstanding and exercisable as at September 30, 2015 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)**
0.91 – 1.50	7,090,000	0.91	4.43	-	-	-
1.51 – 3.00	14,469,003	2.31	3.43	5,634,598	2.33	3.29
3.01 – 4.50	1,811,500	3.70	1.75	1,660,837	3.74	1.72
4.51 – 6.00	3,732,500	5.01	0.63	3,732,500	5.01	0.63
6.01 – 7.66	315,000	6.91	0.69	315,000	6.91	0.69
	27,418,003	2.46	3.17	11,342,935	3.55	2.12

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, 2015, 7,195,000 options were granted (2014 – 8,006,000) and during the three months ended September 30, 2015, no options were granted (2014 – 35,000). 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	**2015**	2014	**2015**	2014
Risk free interest rate (%)	**-**	1.3	**0.7**	1.3
Dividend yield (%)	**-**	0.0	**0.0**	0.0
Expected life (years)	**-**	3.7	**3.6**	3.6
Expected volatility (%)	**-**	50.2	**53.5**	50.7
Forfeiture rate (%)	**-**	14.4	**13.6**	15.1
Weighted average fair value of options	**-**	$ 0.88	**$ 0.36**	$ 1.02

(d) Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Gross stock-based compensation	**$ 1,358**	$ 1,539	**$ 4,314**	$ 3,960
Recoveries from forfeitures	**(10)**	(9)	**(58)**	(238)
Net stock-based compensations before capitalization	**1,348**	1,530	**4,256**	3,721
Stock-based compensation capitalized to property, plant and equipment	**(47)**	(70)	**(146)**	(171)
Net stock-based compensation	**$ 1,301**	**$** 1,460	**$ 4,110**	**$** 3,551

(e) 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	
	2015	2014	**2015**	2014
Net and comprehensive income (loss)	**$ 5,402**	$ 7,013	**$ (15,621)**	$ 10,571
Weighted average number of common shares - basic	**335,638**	335,638	**335,638**	325,167
Dilutive effect:				
Outstanding options	**-**	1	**-**	482
Weighted average number of common shares - diluted	**335,638**	335,639	**335,638**	325,650
Basic income (loss) per share	**$ 0.01**	$ 0.02	**$ (0.05)**	$ 0.03
Diluted income (loss) per share	**$ 0.01**	$ 0.02	**$ (0.05)**	$ 0.03

For the nine months ended September 30, 2015, the Company used a weighted average market closing price of $0.97 (2014 - $2.44) per share to calculate the dilutive effect of stock options. For the nine months ended September 30, 2015, all outstanding options were anti-dilutive (2014 – 15,541,775) and were not included in the calculation of diluted loss per share.

12. COMMITMENTS AND CONTINGENCIES

	2015	2016	2017	2018	2019	Thereafter
Operating leases (1)	$ 513	$ 1,610	$ 270	$ 220	$ 84	$ -
Electrical service agreement (2)	263	520	119	119	119	2,106
Transportation service agreement (3)	33	135	135	135	135	33
	$ 809	$ 2,265	$ 524	$ 474	$ 338	$ 2,139

(1) The Company has 12 months remaining on an operating lease for office space as at September 30, 2015. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their share of the lease obligation, BlackPearl would be required to pay a maximum additional amount of $3.2 million (including an estimate for operating costs) over the next 12 months. At September 30, 2015, no amounts were owed (2014 – no amounts owing).

(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.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at September 30, 2015 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, 2015		December 31, 2014	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Loans and receivables:				
Cash and cash equivalents	$ 4,563	$ 4,563	$ 2,918	$ 2,918
Trade and other receivables	$ 9,613	$ 9,613	$ 17,429	$ 17,429
Deposits	$ 409	$ 409	$ 427	$ 427
Financial assets at fair value through profit or loss:				
Risk management assets	$ 8,250	$ 8,250	$ 20,628	$ 20,628
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 15,782	$ 15,782	$ 61,036	$ 61,036
Long-term Debt	$ 97,000	$ 97,000	$ 29,000	$ 29,000
Financial liabilities at fair value through profit or loss:				
Risk management liabilities	$ 703	$ 703	$ -	$ -

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 are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

(b) Risks associated with financial instruments

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

(i) Credit Risk

Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate this risk by assessing the financial strength of its counterparties and entering into relationships with larger purchasers with established credit history. During 2015, the Company did not experience any collection issues with its marketers. At September 30, 2015, over 60% of total accounts receivable are for crude oil sales revenue (December 31, 2014 – 66%).

During the first nine months of 2015, the Company had four customers (December 31, 2014 – five) which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these customers represented approximately 84% (December 31, 2014 – 73%) of the Company's total oil and gas sales during the first nine months of 2015.

Risk management assets 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. At September 30, 2015, the Company had a $3.6 million (December 31, 2014 - $4.0 million) receivable related to the risk management contracts. During 2015, the Company did not experience any collection issues with its risk management contracts.

As at September 30, 2015, the Company held $4.6 million (December 31, 2014 - $2.9 million) in cash at various major financial institutions throughout Canada and the USA. At September 30, 2015, one Canadian financial institution held over 72% (December 31, 2014 – 64%) of our cash and short-term deposits.

(ii) Liquidity risk

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, 2015, the Company had $53 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:

	<6 Months	**6 months - 1 Year**	**1 - 2 Years**
Accounts payable and accrued liabilities	$15,782	-	-
Risk management liabilities	-	-	$703
Long-term Debt	-	$15,000	$82,000

(iii) Interest Rate Risk

The Company is exposed to interest rate risk related to interest expense on its credit facilities due to the floating interest rate charged on advances. For the period ended September 30, 2015, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the period would have been approximately $55,000 lower. In addition, the Company is exposed to interest rate risk on its excess cash balances. As at September 30, 2015, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the nine months ended September 30, 2015 would have been approximately $38,000 higher.

(iv) Foreign currency exchange risk

The Company manages its foreign currency exchange risk by monitoring foreign exchange rates and evaluating their effects on using Canadian or U.S. vendors as well as timing of transactions. As at September 30, 2015, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at September 30, 2015, the Company held US $1.1 million (December 31, 2014 - US $1.3 million) cash and cash equivalents and US $80,000 (December 31, 2015 - US $35,000) accounts payable and accrued liabilities.

As at September 30, 2015, if exchange rates to convert from US dollars to Canadian dollars had been $0.10 lower with all other variables held constant, after tax net loss for the nine months ended September 30, 2015 would have been approximately $100,000 lower. An equal opposite impact would have occurred to net loss 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 6% (2014 – 5%) 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 (loss).

Risk management amounts recognized during 2015 were as follows:

	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Realized gain (loss) on risk management contracts	**$ 7,940**	$ (468)	**$ 26,893**	$ (3,976)
Unrealized gain (loss) on risk management contracts	**11,826**	4,961	**(13,081)**	(69)
Gain (loss) on risk management contracts	**$ 19,766**	$ 4,493	**$ 13,812**	$ (4,045)

Reconciliation of unrealized risk management contracts were as follows:

	Nine months ended September 30, 2015		Year ended December 31, 2014	
	Fair Value	**Unrealized gain (loss)**	Fair Value	Unrealized gain (loss)
Fair value of contracts, beginning of period	**$ 20,628**	**$ -**	$ -	$ -
Fair value of contracts realized in place at beginning of period	**(18,953)**	**(18,953)**	-	-
Change in fair value of contracts in place at beginning of period	**(1,675)**	**(1,675)**	-	-
Fair value of contracts realized entered into during the period	**(7,940)**	**(7,940)**	(1,870)	(1,870)
Change in fair value of contracts entered into during the period	**15,487**	**15,487**	22,498	22,498
Fair value of contracts, end of period	**$ 7,547**	**$ (13,081)**	$ 20,628	$ 20,628
Current portion of fair value of contracts	**$ 8,250**		$ 20,628	
Non-current portion of fair value of contracts	**$ (703)**		$ -	

The table below summarizes the Company's outstanding commodity contracts as at September 30, 2015:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded	Fair value
<u>2015</u>						
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap	$ 2,031
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap	1,714
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap	1,829
Oil	1,000 bbls/d	October 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/bbl	Swap	2,725
<u>2016</u>						
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 70.65/bbl	Swap	1,869

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded	Fair value
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.00/bbl	Swap	449
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 67.10/bbl	Swap	490
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call	(651)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call	(651)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)	(137)
2017						
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	USD$ WTI	USD$ 60.00/bbl	Sold Call	(2,121)
Total						$ 7,547

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect on December 31, 2015 to exercise the option to enter into the oil swap.

As at September 30, 2015, a 10% decrease to the price outlined in the contracts above used to calculate unrealized gains and losses for the risk management contracts would result in a $180,000 decrease in after tax net income.

14. SUPPLEMENTARY INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Cash interest paid	**$ 923**	$ 191	**$ 2,568**	$ 837
Cash taxes paid	**$ 41**	$ 19	**$ 100**	$ 63

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

	Three months ended September 30		Nine months ended September 30	
	2015	2014	**2015**	2014
Gross interest and financing charges	**$ 923**	$ 191	**$ 2,568**	$ 837
Capitalized interest and financing charges	**(786)**	(173)	**(2,066)**	(380)
Net interest and financing charges	**137**	18	**502**	457
Accretion of decommissioning liabilities	**431**	392	**1,276**	1,151
Finance costs	**$ 568**	$ 410	**$ 1,778**	$ 1,608

(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	
	2015	2014	**2015**	2014
Changes in non-cash working capital:				
Trade and other receivables	**$ 5,956**	$ 1,748	**$ 8,854**	$ 657
Inventory	**(8)**	-	**299**	-
Prepaid expenses and deposits	**288**	482	**(1,147)**	(719)
Accounts payable and accrued liabilities	**(12,632)**	12,985	**(45,159)**	26,168
	$ (6,396)	$ 15,215	**$ (37,153)**	$ 26,106
Relating to:				
Operating activities	**$ 4,177**	$ 1,991	**$ 12,480**	$ (1,161)
Investing activities	**(10,573)**	13,224	**(49,633)**	27,267
Changes in non-cash working capital	**$ (6,396)**	$ 15,215	**$ (37,153)**	$ 26,106