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NEWS RELEASE **May 6, 2015**

BLACKPEARL ANNOUNCES FIRST 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 months ended March 31, 2015.

Highlights include:

- Construction of the 6,000 barrels per day first phase of the Onion Lake thermal project is complete and commissioning of the facilities has begun, the project was ahead of schedule and within budget;
- At Blackrod, the pilot results from the second SAGD well pair continue to be positive, the well is currently producing in excess of 500 barrels of oil per day with a steam oil ratio of under 3;
- Despite low oil prices which resulted in a 63% decrease in revenues to $22.1 million, funds flow from operations was $13 million;
- Production averaged 8,269 barrels of oil equivalent (boe) per day, a 12% decrease compared to Q1 2014 volumes - the lower production volumes reflect, in part, the Company's decision to shut-in 40 wells during a period of extremely low oil prices.

John Festival, President of BlackPearl commented "Low crude oil prices made for a challenging Q1 for BlackPearl and most of industry. However, Q1 was a very exciting period for us. We recently completed construction of the first phase of the Onion Lake thermal project and we have started commissioning the facilities. The project was completed ahead of schedule and capital costs were right in line with our budget of $223 million. We are looking forward to commencing steam injection in the wells later this month and initial oil production should begin three to six months after that. This is an important milestone for BlackPearl. Our first thermal project has been completed successfully and it is the largest project the Company has undertaken. Production from the Onion Lake thermal project should be some of our lowest cost production, which is critical in this lower oil price environment".

Property Review

Onion Lake

In 2015, we achieved some important milestones with the Onion Lake thermal project. Construction of the first phase of the thermal project was completed in April and we started commissioning various components of the central processing facilities, well pads and source water facilities. Commissioning is expected to take four to eight weeks. We are planning to begin steam injection to the first well pad (seven wells) by the end of May. First oil production is expected approximately three to six months after we start steam injection. Oil production ramp-up to design capacity of 6,000 barrels per day is expected to take 12 to 18 months after initial steam injection.

This phase of the project includes 13 horizontal production wells on two well pad sites. All of these wells were drilled in late 2014 and were completed during the first quarter of 2015. In addition, we have 35 vertical steam injection wells which were completed during the first quarter. The steam generation facilities are designed to generate approximately 17,000 barrels of steam per day. Final capital costs for this phase of the project are estimated to be between $220 and $225 million, which is in line with our original budget estimates. No new conventional drilling occurred during the first quarter of 2015 due to low oil prices. In addition, after an extensive well by well review of our operations we shut-in 40 producing wells at Onion Lake during the first quarter. These wells were some of the higher cost wells to operate in the field and were not economic at current oil prices. These 40 wells were cumulatively producing approximately 1,000 barrels of oil per day before they were shut-in. We plan to bring these wells back on production as oil prices improve.

Blackrod

We continue to achieve encouraging results from the second pilot well pair at Blackrod. Technical analysis indicated that the steam chamber was continuing to build and that the well was still in its production ramp-up phase. In order to optimize well performance a planned well intervention was scheduled for February which impacted production rates in the first quarter. The well was put back on production in March and in April produced in excess of 500 barrels of oil per day at a steam oil ratio of 2.6, and is continuing to ramp up. Cumulatively, the well has produced in excess of 115,000 barrels of oil.

We continue to advance our regulatory application for an 80,000 barrel per day commercial development project at Blackrod. The Alberta Energy Regulator ("AER") is continuing with their final review of the application. We have not received any additional supplemental requests for information from the AER. During this time we have continued consultations with First Nations and other stakeholders in the area to ensure their concerns have been addressed. It is expected that final approval of the application will be obtained in the next few months.

Mooney

No new activities were initiated at Mooney during the first quarter due to low oil prices. Expansion of the ASP flood to the phase two lands has been deferred until oil prices improve. Our focus during the first quarter was to review operations and flood development. As a result of this review, we were able to significantly reduce operating costs at Mooney, primarily by optimizing the amount of chemical injection in certain areas of the reservoir due to the maturity of the flood in those areas.

Production

Oil and gas production averaged 8,269 barrels of oil equivalent per day in the first quarter of 2015, a 12% decrease compared with the first quarter of 2014. The decrease in oil production in the first quarter of 2015 is attributable to a number of factors. Due to low oil prices we did not undertake any new drilling activities during the quarter. No new drilling combined with natural production declines at Onion Lake and Mooney resulted in an overall drop in production from these areas. In addition, 40 producing wells in the Onion Lake area were shut-in during the quarter due to low oil prices. In many instances, these were wells with high operating costs that required well servicing and we chose to shut them in rather than incur the expenses to bring them back on production. At the time these wells were shut-in they were producing approximately 1,000 barrels of oil per day. We plan to put these wells back on production when oil prices recover to a level that they can contribute positive cash flow to our operations. Finally, at Blackrod, we shut-in the second pilot well pair for part of the quarter to complete a workover on the well which resulted in lower average production from the area during the quarter.

Average Daily Sales Volume

Production by area (boe/d)	**Q1 2015**	Q4 2014	Q1 2014
Onion Lake	**3,959**	4,651	4,274
Mooney	**2,797**	3,236	3,696
John Lake	**1,011**	1,109	1,069
Other	**96**	120	113
Blackrod	**406**	523	211
	8,269	9,639	9,363

Financial Results

Oil and gas revenues decreased 63% in the first quarter of 2015 to $22.1 million compared with $59.6 million in Q1 2014. The decrease in revenues is attributable to a 57% decrease in our average sales price and a 12% decrease in production volumes. Our realized oil price (before the effects of risk management activities) in Q1 2015 was $32.05 per barrel compared to $73.23 per barrel in 2014. The decrease in our realized wellhead price reflects significantly lower WTI reference oil prices in Q1 2015 compared with Q1 2014 (US$48.63/bbl vs US$98.68/bbl), partially offset by tighter heavy oil differentials (US$14.71/bbl vs US$23.11/bbl) and a weaker Canadian dollar relative to the US dollar ($0.806 vs $0.906).

Our oil hedging program has helped mitigate some of the negative impact of the low oil price environment in 2015. During the first quarter we realized a gain of $13.7 million from our oil hedging program, which was the equivalent of adding $19.37 per barrel to our wellhead price in the quarter. The following summarizes the hedging contracts we currently have outstanding:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	April 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call Swaption(1)
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

(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 decreased 19% in the first quarter of 2015 to $15.9 million from $19.7 million in the same period in 2014. On a per boe basis, production costs were $22.48 per boe in Q1 2015, a decrease from $23.88 per boe in Q1 2014. The decrease in production expenses in 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 certain suppliers and contractors, deferring well servicing work and shutting-in specific wells that are not economic at current oil prices.

The significantly reduced revenue, partially offset by lower royalties, transportation costs and operating costs resulted in a 44% decrease in funds flow from operations in Q1 2015 to $12.9 million compared to $23.0 million for the same period in 2014.

Financial and Operating Highlights

	Three months ended March 31 2015	2014
Daily production / sales volumes(1)		
Oil (bbl/d)	7,885	9,122
Natural gas (mcf/d)	2,303	1,448
Combined (boe/d)	8,269	9,363
Product pricing ($) (before the effects of hedging transactions)		
Crude oil - per bbl	32.05	73.23
Natural gas - per mcf	2.63	5.41
Combined - per boe	31.25	72.30
($000's, except per share and boe amounts)		
Revenue		
Oil and gas revenue – gross	22,115	59,555
Gain (loss) on risk management contracts:		
Risk management contracts - realized	13,708	(666)
Risk management contracts - unrealized	(11,374)	(5,301)
	2,334	(5,967)
Royalties ($/boe)	5.78	14.00
Transportation costs ($/boe)	1.10	1.87
Operating costs ($/boe)	22.48	23.88
Loss for the period	(10,944)	(1,126)
Per share, basic and diluted	(0.03)	(0.00)
Funds flow from operations(2)	12,940	23,037
Capital expenditures	42,981	49,360
Working capital, end of period	(11,137)	28,192
Long term debt	78,000	-
Shares outstanding, end of period	335,638,226	328,398,308

(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)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.

The 2015 first quarter report to shareholders, including the financial statements, management's discussion and analysis and notes to the financial statements are available on the Company's website (www.blackpearlresources.ca) or SEDAR (www.sedar.com).

This news release includes terms commonly used in the oil and natural gas industry, such as funds flow and funds flow from operations which represent cash flow from operating activities expressed before decommissioning costs incurred and changes in non-cash working capital. 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 if incurred in the future. These terms do not have standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Consequently, these are referred to as non-GAAP measures.

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; capital expenditure and drilling programs including the target date of the end of May for first steam injection at the Onion Lake EOR project and anticipated timing of initial oil production three to four months after steam injection at the Onion Lake EOR project, anticipated final capital costs of between $220 and $225 million for the first phase of the Onion Lake EOR project, reaching peak production rates 12 to 18 months after steam injection at Onion Lake, timing as to when we would bring back on production the Onion Lake wells that were shut-in due to low oil prices and expected timing to receive regulatory approval for our commercial development application at Blackrod.

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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BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three months ended March 31, 2015. These results are being compared with the three months ended March 31, 2014. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended March 31, 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		

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" and "operating netback". 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 production sales less royalties, production costs and transportation costs, divided by total production for the period on a boe basis.

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.

($000s)	**Q1 2015**	Q4 2014	Q1 2014
Cash flows from operating activities (1)	**23,849**	10,242	18,517
Add (deduct):			
Decommissioning costs incurred	**245**	263	204
Changes in non-cash working capital related to operations	**(11,154)**	9,211	4,316
Funds flow from operations (2)	**12,940**	19,716	23,037

(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 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

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

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

The effective date of this MD&A is May 6, 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 with a thermal EOR project under construction;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property 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 Q1 2015, with WTI oil prices averaging US$48.63 per bbl during the quarter compared to US$98.68 per bbl barrel in Q1 2014.

- Capital expenditures during the first quarter were $43.0 million, with approximately $39.8 million related to the construction of the Onion Lake thermal EOR project, $2.1 million spent at Blackrod related to continued capitalization of net revenues from operating the Blackrod pilot and $1.1 million spent in other areas.

- Oil and gas sales during the first quarter were $22.1 million and funds flow from operations (non-GAAP measure) were $12.9 million. For the quarter ended March 31, 2015, the Company incurred a net loss of $10.9 million.

- The first phase of the Onion Lake EOR project is being designed for production of approximately 6,000 bbls/d of oil; target date for completion of construction and first steam is mid-2015. Initial oil production from the project is expected within three months of steam injection and peak production rates are expected 12 to 18 months after initial steam injection. At March 31, 2015, delivery of all the modules for the central processing facilities had occurred and approximately 90% of the field construction was completed.

- Subsequent to March 31, 2015, construction of the Onion Lake EOR project was completed and commissioning of the facilities has begun.

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

- At March 31, 2015, BlackPearl had a working capital deficiency of $11.1 million and $78 million in long-term debt, leaving $72 million available to be drawn under the Company's existing credit facilities.

SELECTED QUARTERLY INFORMATION

	2015		**2014**				2013	
($000s, except where noted)	**Mar 31**	**Dec 31**	**Sep 30**	**Jun 30**	Mar 31	Dec 31	Sep 30	Jun 30
Production (boe/d) (1)	**8,269**	**9,639**	**9,248**	**8,897**	9,363	10,454	9,382	9,986
Oil and gas sales	**22,115**	**47,798**	**58,818**	**62,174**	59,555	54,072	69,092	58,322
Oil and gas sales ($/boe)	**31.25**	**57.00**	**72.90**	**79.53**	72.30	57.67	82.72	66.20
Production costs	**15,905**	**21,066**	**21,021**	**20,291**	19,673	18,420	16,664	18,413
Production costs ($/boe)	**22.48**	**25.12**	**26.05**	**25.96**	23.88	19.65	19.95	20.90
Gain (loss) on risk management contracts	**2,334**	**26,543**	**4,493**	**(2,571)**	(5,967)	-	-	-
Net income (loss)	**(10,944)**	**16,254**	**7,013**	**4,684**	(1,126)	226	9,270	2,597
Per share, basic and diluted ($)	**(0.03)**	**0.05**	**0.02**	**0.01**	0.00	0.00	0.03	0.01
Capital expenditures	**42,981**	**57,700**	**80,262**	**48,044**	49,360	22,749	24,326	27,315
Funds flow from operations (2)	**12,940**	**19,716**	**23,809**	**23,161**	23,037	20,735	32,609	22,823
Per share, basic and diluted ($)	**0.04**	**0.06**	**0.07**	**0.07**	0.08	0.07	0.11	0.08
Cash flow from operating activities	**23,849**	**10,242**	**25,587**	**24,042**	18,517	23,772	33,090	20,592
Total assets (end of period)	**866,018**	**837,773**	**785,538**	**765,233**	747,763	652,216	648,554	647,839
Shares outstanding (000s)	**335,638**	**335,638**	**335,638**	**335,638**	328,398	300,425	296,306	296,122
Weighted average shares outstanding (000s)								
Basic	**335,638**	**335,638**	**335,638**	**334,817**	304,841	298,843	296,244	296,113
Diluted	**335,638**	**335,638**	**335,638**	**335,244**	305,874	300,768	298,584	299,693

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

(2) Funds flow from operations is a non-GAAP measure 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

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

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US$/bbl)	48.63	73.15	97.17	102.99	98.68	97.46	105.83	94.29
Western Canadian Select (WCS) (Cdn$/bbl)	42.11	66.73	83.80	90.42	83.39	68.43	91.75	76.68
Differential – WCS/WTI (US$/bbl)	14.71	14.39	20.24	20.08	23.11	32.21	17.48	19.36
Differential - WCS/WTI (%)	30.2%	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%	20.6%
Average Natural Gas Prices								
AECO gas (Cdn$/GJ)	2.61	3.41	3.81	4.71	4.91	2.99	2.67	3.40
Average Foreign Exchange (US$ per Cdn$1)	0.806	0.881	0.918	0.917	0.906	0.950	0.962	0.977

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 decreased sharply during the fourth quarter of 2014 and the decrease in prices continued in the first quarter of 2015. The decrease has been attributed to a number of factors including 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. This sharp decrease in oil prices has led to a significant drop in planned drilling activity and capital spending in the industry. WTI oil prices averaged US$48.63 per bbl during the first quarter of 2015, down from US$98.68 per bbl in the same period in 2014. WTI oil prices have improved modestly in the second quarter of 2015 and are currently trading around US$60 per bbl. Heavy oil differentials narrowed to US$14.71 per bbl in Q1 2015 compared to US$23.11 per bbl in the same period in 2014; however, heavy oil differentials as a percentage of WTI prices widened to 30.2% in the first quarter of 2015 compared to 23.4% in the same period in 2014. The improvement in heavy oil differentials has been attributed to increased refining capacity in the US, additional pipeline capacity to the US Gulf Coast and increased rail capacity providing access to US heavy oil refineries.

Natural gas prices decreased during the first quarter of 2015 averaging $2.61/GJ compared to $4.91/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 move toward commercial development of our two thermal projects 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$0.81 during the first quarter of 2015 compared to Cdn$1 = US$0.86 at December 31, 2014.

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

	Q1 2015	Q4 2014	Q1 2014
Daily production/sales volumes (1)			
Oil (bbls/d)	**7,479**	8,567	8,911
Natural gas (Mcf/d)	**2,303**	3,294	1,448
Combined (boe/d)	**7,863**	9,116	9,152
Bitumen – Blackrod (bbls/d) (2)	**406**	523	211
Total production (boe/d)	**8,269**	9,639	9,363
Product pricing (excluding risk management activities) (2)			
Oil ($/bbl)	**32.05**	59.34	73.23
Natural gas ($/Mcf)	**2.63**	3.39	5.41
Combined ($/boe)	**31.25**	57.00	72.30
Sales ($000s) (2)			
Oil and gas sales – gross	**22,115**	47,798	59,555
Royalties	**(4,089)**	(9,655)	(11,529)
Oil and gas sales – net	**18,026**	38,143	48,026

(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.

Oil and natural gas sales decreased 63% in the first quarter of 2015 to $22.1 million from $59.6 million in the same period in 2014. The decrease in oil and gas sales is attributable to a 57% decrease in average sales prices received in the first quarter of 2015 compared to the same period in 2014 and a 12% decrease in production (on a boe basis).

Significantly lower 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 first quarter of 2015. Our average oil wellhead sales price, prior to the impact of risk management activities, decreased 56% in the first quarter of 2015 to $32.05 per bbl compared with $73.23 per bbl in the same period in 2014.

The decrease in oil production in the first quarter of 2015 is attributable to a number of factors. Due to low oil prices we did not undertake any new drilling activities during the quarter. No new drilling combined with natural production declines at Onion Lake and Mooney resulted in an overall drop in production from these areas. In addition, 40 producing wells in the Onion Lake area were shut-in during the quarter due to low oil prices. In many instances, these were wells with high operating costs that required well servicing and we chose to shut them in rather than incur the expenses to bring them back on production. At the time these wells were shut-in they were producing approximately 1,000 barrels of oil per day. We plan to put these wells back on production when oil prices recover to a level that they can contribute positive cash flow to our operations. Finally, at Blackrod, we shut-in the second pilot well pair for part of the quarter to complete a workover on the well which resulted in lower average production from the area during the quarter.

On a boe basis, 95% of the Company’s oil and natural gas production in the first quarter of 2015 was heavy oil or bitumen. The Onion Lake area accounted for 50% and the Mooney area accounted for 36% of total production in the first quarter of 2015.

Production by area (boe/d)	**Q1 2015**	Q4 2014	Q1 2014
Onion Lake	**3,959**	4,651	4,274
Mooney	**2,797**	3,236	3,696
John Lake	**1,011**	1,109	1,069
Other	**96**	120	113
Blackrod	**406**	523	211
	8,269	9,639	9,363

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. 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 the commercial production of oil and gas has commenced. As of March 31, 2015, BlackPearl had not received regulatory approval for the commercial Blackrod project. A second pilot well pair was drilled in 2013 and steam injection in this well pair commenced during the fourth quarter of 2013. After the initial warm up phase the well pair was converted to SAGD mode (production test phase) in March 2014. Production is expected to ramp-up to peak rates in 2015. During the first quarter of 2015, the pilot wells produced an average of 406 bbls/d of bitumen and the net revenues capitalized were a loss of $1.2 million ($1.3 million loss in the first quarter of 2014).

Risk Management Activities

The Company has periodically entered 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. 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. The current policy permits management to enter into risk management contracts up to 60% of budgeted production volumes for a maximum period of two years.

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 $2.3 million on its risk management contracts during the first quarter of 2015, consisting of a $13.7 million realized gain on the contracts and an unrealized loss of $11.4 million. The unrealized loss is primarily due to the realization of settled contracts. The realized gain on risk management contracts was the equivalent of adding $19.37 per bbl to our wellhead price.

($000s, except per boe)	**Q1 2015**	Q4 2014	Q1 2014
Realized gain (loss) on risk management contracts	**13,708**	5,846	(666)
Per boe ($)	**19.37**	6.97	(0.81)
Unrealized gain (loss) on risk management contracts	**(11,374)**	20,697	(5,301)

The table below summarizes the Company's commodity contracts as at March 31, 2015:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	April 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call Swaption(1)

(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.

Subsequent to March 31, 2015, the Company entered into the following commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/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

Royalties

	Q1 2015	Q4 2014	Q1 2014
Royalties ($000s)	**4,089**	9,655	11,529
Per boe ($)	**5.78**	11.51	14.00
As a percentage of oil and gas sales	**18%**	20%	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 as a percentage of revenue decreased to 18% of revenues in the first quarter of 2015 from 19% of revenues in the same period in 2014. The decrease in the royalty as a percentage of revenue and royalty per boe in the first quarter of 2015 as compared to the same period in 2014 is attributed to lower wellhead prices in 2015, which impact royalty rates. During the first quarter of 2015 we also amended the royalty calculations for certain previous periods. Without this amendment the average royalty rate in the first quarter of 2015 would have been approximately 15%.

Royalties as a percentage of revenues is expected to continue to drop as a result of the commencement of production, later in 2015, from the Onion Lake EOR project. During the pre-payout period, royalties paid on revenues from this project are expected to be approximately 10%.

Transportation Costs

	Q1 2015	Q4 2014	Q1 2014
Transportation costs ($000s)	**781**	1,240	1,539
Per boe ($)	**1.10**	1.48	1.87

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 49% in the first quarter of 2015 to $0.8 million from $1.5 million in the same period in 2014. The decrease in transportation costs is primarily attributable to lower production volumes in Q1 2015. However, in addition to lower production volumes, during the first quarter at Onion Lake, we shipped more of our volumes as emulsion rather than as clean marketable barrels. This results in lower clean oil transportation costs but it increases production expenses.

Production Costs

	Q1 2015	Q4 2014	Q1 2014
Production costs ($000s)	**15,905**	21,066	19,673
Per boe ($)	**22.48**	25.12	23.88

Production costs decreased 19% in the first quarter of 2015 to $15.9 million from $19.7 million in the same period in 2014. On a per boe basis, production costs decreased 6% in the first quarter of 2015 to $22.48 per boe from $23.88 per boe in the same period in 2014.

The decrease in production expenses in 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 certain 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)

($/boe)	**Q1 2015**	Q4 2014	Q1 2014
Revenues	**31.25**	57.00	72.30
Royalties	**5.78**	11.51	14.00
Transportation costs	**1.10**	1.48	1.87
Production costs	**22.48**	25.12	23.88
Operating netback excluding realized risk management contracts	**1.89**	18.89	32.55
Realized gain (loss) on risk management contracts	**19.37**	6.97	(0.81)
Operating netback including realized risk management contracts	**21.26**	25.86	31.74

(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 94% in the first quarter of 2015 to $1.89 per boe from $32.55 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)

($000s, except per boe)	**Q1 2015**	Q4 2014	Q1 2014
Gross G&A expense	**2,499**	2,417	3,625
Operator recoveries	**(360)**	(516)	(510)
Net G&A expense	**2,139**	1,901	3,115
Per boe ($)	**3.02**	2.27	3.78

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The decrease in G&A expenses in the first quarter of 2015 compared to the same period in 2014 is primarily attributable to lower performance incentives payments to staff in the first quarter of 2015 compared to the same period in 2014 as a result of the drop in oil prices over the last six months.

Stock-Based Compensation

($000s, except per boe)	**Q1 2015**	Q4 2014	Q1 2014
Gross stock-based compensation	**1,628**	2,462	941
Recoveries from forfeitures	**(45)**	(35)	(169)
Net stock-based compensation before capitalization	**1,583**	2,427	772
Capitalized stock-based compensation	**(53)**	(87)	(31)
Net stock-based compensation	**1,530**	2,340	741
Per boe ($)	**2.16**	2.79	0.90

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 quarter of 2015 compared to the same period in 2014 reflects an increase in the number of options issued. In the first quarter of 2015, 7,165,000 options were granted, 228,334 options were forfeited and 30,000 options expired.

During the first quarter of 2015, $53,000 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 EOR project.

Finance Costs

($000s)	**Q1 2015**	Q4 2014	Q1 2014
Gross interest & financing charges	**583**	303	150
Capitalized interest & financing charges	**(520)**	(254)	(89)
Net interest & financing charges	**63**	49	61
Accretion of decommissioning liabilities	**417**	381	371
Total finance costs	**480**	430	432

The increase in gross interest & financing charges in the first quarter of 2015 compared to the same period in 2014 is a result of higher weighted average debt levels in 2015. During the first quarter of 2015, $519,000 of interest costs related to the construction of the Onion Lake EOR project were capitalized.

The average interest rate on advances under the Company's credit facilities was 3.07% in the first quarter of 2015. This does not include standby fees charged on unutilized amounts of the credit facilities.

Depletion and Depreciation

	Q1 2015	Q4 2014	Q1 2014
Depletion and depreciation ($000s)	**13,765**	15,143	17,886
Per boe ($)	**19.45**	18.06	21.71

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 23% in the first quarter of 2015 to $13.8 million from $17.9 million in the same period in 2014. The decrease in depletion is primarily a result of lower production volumes in 2015.

On a boe basis, depletion and depreciation expense decreased to $19.45 per boe in the first quarter of 2015 as compared to $21.71 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 most current third party reserves evaluation.

As of March 31, 2015, $255.0 million of expenditures included in property, plant and equipment that relate to the Onion Lake EOR project are not subject to depletion until production at this project begins. Exploration and evaluation assets of $168.6 million are also not subject to depletion.

Interest Income

	Q1 2015	Q4 2014	Q1 2014
Interest income ($000s)	**6**	16	29

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 first quarter of 2015 compared to the same period in 2014.

Income Taxes

($000s)	**Q1 2015**	Q4 2014	Q1 2014
Current income tax	**30**	55	18
Deferred income tax (recovery)	**(3,265)**	6,281	(181)
Total income tax (recovery)	**(3,235)**	6,336	(163)

BlackPearl did not pay cash income taxes in the first quarter 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 the first quarter of 2015 is a result of capital tax. The Company recorded a deferred income tax recovery of $3.3 million for the first quarter of 2015 as a result of a taxable loss during the period.

RESULTS FROM OPERATIONS

	Q1 2015	Q4 2014	Q1 2014
Net income (loss) ($000s)	**(10,944)**	16,254	(1,126)
Per share, basic ($)	**(0.03)**	0.05	(0.00)
Per share, diluted ($)	**(0.03)**	0.05	(0.00)

For the quarter ended March 31, 2015, the Company incurred a net loss of $10.9 million compared to net loss of $1.1 million in the same period in 2014. The increase in net loss in the first quarter of 2015 compared to the same period in 2014 is primarily a result of a lower wellhead sales price in 2015, partially offset by the gain on risk management contracts and lower royalties and production costs.

	Q1 2015	Q4 2014	Q1 2014
Funds flow from operations [1] ($000s)	**12,940**	19,716	23,037
Per share, basic ($)	**0.04**	0.06	0.08
Per share, diluted ($)	**0.04**	0.06	0.08

(1) 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 and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

Funds flow from operations decreased 44% to $12.9 million during the first quarter of 2015 compared to $23.0 million in the same period in 2014. The decrease in funds flow in the first quarter of 2015 compared to the same period in 2014 is primarily a result of lower wellhead sales prices in 2015, partially offset by the realized gain on risk management contracts.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2015, the Company had a working capital deficiency (current assets less current liabilities) of $11.1 million. The working capital deficiency is expected to be funded from cash flows from operating activities and the undrawn amount available on our credit facilities.

At March 31, 2015, the Company had $78 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $72 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 May 31, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2015. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

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 2.2:1 at March 31, 2015 (December 31, 2014 – 2.3:1) and is in compliance with this covenant at March 31, 2015 and throughout the first quarter of 2015.

($000s, except working capital ratio)	**March 31, 2015**	December 31, 2014
Current assets per consolidated financial statements	**31,239**	43,651
Add: amount available to drawn on credit facilities	**72,000**	121,000
Less: risk management assets	**(9,254)**	(20,628)
Current assets for working capital ratio	**93,985**	144,023
Current liabilities per consolidated financial statements	**42,376**	61,888
Working capital ratio	**2.2**	2.3

The current low oil price environment has resulted in the Company electing to defer the ongoing development of its conventional heavy oil projects at Mooney, Onion Lake and other minor project areas in order to maintain financial flexibility. If oil prices improve, we are in a position to resume our capital programs in these areas.

The first phase of the Onion Lake EOR project is under construction. It is being designed for production of 6,000 bbls/d of oil and capital costs are expected to be approximately $225 million. At March 31, 2015, the Company had spent approximately $206.7 million on the first phase of the Onion Lake EOR project. The first phase of the project is being funded from amounts available from our credit facilities, proceeds from share issuances in 2014 (aggregate gross proceeds of $88.4 million) and funds flow from operations. Construction is expected to be completed and first steam injection by mid-2015.

The Company is planning to build the Blackrod SAGD project in phases as well, with the first phase likely to be designed for 20,000 bbls/d of oil. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. Regulatory approval of the first phase of the Blackrod SAGD project is expected in 2015. Timing of development of this project is dependent on obtaining additional financing. We may consider joint venture opportunities to accelerate development of this project.

The Company did not pay dividends on its common shares in the first quarter 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

During the quarter ended March 31, 2015, capital spending was $43.0 million, a decrease from $49.4 million during the same period in 2014. The main components of the capital spending program during the first quarter was the construction of the Onion Lake thermal EOR project and the continued capitalization of net revenues from operating the Blackrod pilot.

($000s)	**Q1 2015**	Q4 2014	Q1 2014
Land	**146**	315	253
Seismic	**651**	71	(62)
Drilling and completion	**3,964**	15,774	39,114
Equipment and facilities	**38,145**	41,431	10,052
Other	**75**	109	3
Total	**42,981**	57,700	49,360
Property acquisitions	**-**	-	-
Total capital expenditures	**42,981**	57,700	49,360
Property dispositions	**-**	-	-
Net capital expenditures	**42,981**	57,700	49,360

During the first quarter of 2015, the Company also made a provision for the estimated future decommissioning costs of the Onion Lake thermal EOR project. The present value of these decommissioning costs, which we are unlikely to incur for 25 to 30 years, was $12.6 million.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of financial obligations in the ordinary course of business. The following table summarizes the contractual obligations and commitments of the Company outstanding as at March 31, 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)	1,515	1,563	249	202	84	-
Electrical service agreement (2)	712	520	119	119	119	2,106
Transportation service agreement (3)	102	135	135	135	135	33
Capital commitments (4)	8,150	-	-	-	-	-
Decommissioning liabilities (5)	607	1,900	984	1,056	1,198	60,903
Long-term debt (6)	-	-	78,000	-	-	-
	11,086	4,118	79,487	1,512	1,536	63,042

(1) The Company has 18 months remaining on an operating lease for office space as at March 31, 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 lease obligation, BlackPearl would be required to pay a maximum additional $4.7 million (including an estimate for operating costs) over the next 18 months. At March 31, 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 entered into certain agreements pertaining to the construction of the Onion Lake EOR project.

(5) 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 $83.7 million as at March 31, 2015. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(6) The credit facilities have no fixed terms of repayment. Based on the existing terms of the Company's credit facilities, the first possible mandatory repayment date may come in 2017 assuming the facility is not extended during the scheduled credit facility review in May 2016. At this time management expects the facility will be extended.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 2015 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets, accounts payable and accrued 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).

FOREIGN CURRENCY RISK

As at March 31, 2015, the Company has not entered into any fixed rate contracts to mitigate its currency risks. As at March 31, 2015, the Company held US $1.1 million cash and cash equivalents and US $44,000 accounts payable and accrued liabilities.

The polymer for our ASP flood at Mooney is supplied by a US company and we are required to pay in US dollars. Fluctuations in exchange rates will have an impact in the Company's cost of polymer. In the first quarter of 2015 we spent approximately US$1.0 million on polymer.

As at March 31, 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 period would have been approximately $106,000 lower. An equal opposite impact would have occurred to net loss had exchange rates been $0.10 higher. This calculated effect of change in foreign exchange is for US dollar items held at March 31, 2015 and not transactions that occurred during the period ended March 31, 2015.

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 March 31, 2015, over 58 percent of total accounts receivable are for crude oil sales.

In the first quarter of 2015, the Company had four customers which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these customers represented approximately 78% of the Company's total oil and gas sales in the first quarter of 2015.

At March 31, 2015, the Company had a $1.0 million receivable related to the reimbursement of crown royalties as a result of an enhanced oil recovery incentive program from the Alberta government. These amounts are not considered impaired based on the credit worthiness of the Alberta government and the approval the Company has received on its enhanced oil recovery activities.

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 March 31, 2015, the Company had a $4.5 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 March 31, 2015, the Company held $5.4 million in cash at various major financial institutions throughout Canada and the USA. At March 31, 2015, one Canadian financial institution held over 79% of our cash and short-term deposits.

INTEREST RATE RISK

The Company is exposed to interest rate risk related to interest expense on its revolving credit facility due to the floating interest rate charged on advances. For the period ended March 31, 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 $16,000 lower. In addition, the Company is exposed to interest rate risk on its excess cash balances. As at March 31, 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 $15,000 higher.

LIQUIDITY RISK

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at March 31, 2015, the Company had $72 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

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 5% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current activities. When the Company's thermal projects are commercially developed, natural gas will become a major input cost to the Company.

As at March 31, 2015, if our average oil wellhead sales price decreased $1.00 with all other variables held constant including risk management contracts, after tax net loss for the period would have been approximately $0.4 million lower. An equal opposite impact would have occurred to net loss had average oil wellhead sales price been $1.00 higher.

From time to time, the Company enters into 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.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the first quarter ended 2015 or 2014. We do utilize 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 first quarter ended 2015 or 2014.

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at May 6, 2015, the Company had 335,638,226 common shares outstanding and 27,843,001 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at May 6, 2015, the Company had $89,000,000 amounts drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $60,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of May 6, 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 March 31, 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, 2017 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 Instrument: 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 three 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 three months ended March 31, 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
Production (boe/d)		
Annual average	8,000 – 9,000	8,000 – 9,000
Funds flow from operations ($millions)	15 – 20	25 - 30
Capital expenditures ($millions)	70 – 75	70 – 75
Year-end debt ($millions)	125 - 130	115 - 120
Pricing Assumptions (annual average)		
Crude oil - WTI	US$55.00	US$53.41
Light/heavy differential	US$15.00	US$14.18
Foreign Exchange (Cdn$ to US$)	0.85	0.81

Our plans for the remainder of 2015 are relatively unchanged from the initial guidance we provided at the beginning of the year. We are planning to spend $70 to $75 million on capital projects, unchanged from our initial guidance, and our major focus will be the completion of the Onion Lake thermal project, which will account for over 80% of our 2015 spending. 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 is expected to be funded from a combination of anticipated funds flow from operations, which we are expecting to be between $25 and $30 million, up from our initial guidance of $15 to $20 million, and supplemented with our existing credit facilities. Year-end 2015 debt levels are anticipated to be between $115 and $120 million, down from our initial guidance of $125 to $130 million. The increase in funds flow from operations and lower year-end debt levels reflects a change in the average wellhead price we expect to receive for the remainder of the year (primarily attributable to a change in the assumption for exchange rates between the Canadian and US dollar) and lower operating costs as a result of the cost reduction initiatives we undertook during the first quarter.

We anticipate oil and gas production to average between 8,000 and 9,000 boe/d in 2015, unchanged from our initial guidance, although our production is likely to be closer to the low end of this range due to the wells we shut-in in the first quarter for economic reasons. As a result of these wells being shut-in, exit production levels for 2015 are expected to be between 8,500 and 9,000 boe/d, down from our initial guidance of between 9,000 and 10,000 boe/d.

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 “anticipated”, “approximately”, “planning”, “planned”, “could”, “continued”, “estimate”, “estimates”, “estimated”, “forecast”, “likely”, “expect”, “expected”, “may”, “target”, “intended”, “new”, “will”, “timing”, “temporarily”, “in the event”, “move toward”, “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 initial and peak oil production at the Onion Lake EOR project as discussed in the 2015 Significant Events section;
- Target date for completion of construction and first steam at the Onion Lake EOR project as discussed in the 2015 Significant Events section;
- Future oil and gas prices and their impact on BlackPearl 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;

- Anticipated timing of peak production rates from the second pilot well pair at Blackrod 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 EOR project as discussed in the Royalties section;
- Expected cash taxes to be paid in 2015 in the Income Taxes section;
- The expectation that the working capital deficiency will be funded from cash flows from operating activities and the undrawn amount available on our credit facilities as discussed in the Liquidity and Capital Resources section;
- The required timing of payment on any amounts outstanding on the facilities in the event the lenders elected not to renew the credit facilities as discussed in the Liquidity and Capital Resources section;
- Expected resumption of our capital programs in certain areas if oil prices were to improve as discussed in the Liquidity and Capital resources section;
- The estimated capital costs for the first phase of thermal development at Blackrod and the first phase of thermal development at Onion Lake as discussed in the Liquidity and Capital Resources section;
- Methods, sources and timing to finance capital expenditure programs, particularly for the thermal project at Blackrod as discussed in the Liquidity and Capital resources section;
- Potential production levels for the Blackrod SAGD project and the Onion Lake thermal project in the Liquidity and Capital resources section;
- The Company’s expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section; and
- All of the statements under the Outlook section and the table presented since they are estimates of future conditions and results.

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

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

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

Other Supplementary Information

1. List of directors and officers at May 6, 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
Chris Hogue, Vice President Operations
Ed Sobel, Vice President Exploration
Diane Phillips, Corporate Secretary

2. Financial Information

The report for the period ended June 30, 2015 is expected to be published on or before August 15, 2015.

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		**March 31, 2015**		December 31, 2014
Assets					
Current assets					
Cash and cash equivalents	4	**$**	**5,442**	$	2,918
Trade and other receivables	5		**15,042**		18,467
Inventory			**538**		638
Prepaid expenses and deposits			**963**		1,000
Risk management assets	13		**9,254**		20,628
			31,239		43,651
Exploration and evaluation assets	6		**168,264**		166,344
Property, plant and equipment	7		**666,515**		627,778
		$	**866,018**	$	837,773
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	8	**$**	**41,294**	$	61,036
Current portion of decommissioning liabilities	9		**1,082**		852
			42,376		61,888
Decommissioning liabilities	9		**71,214**		59,831
Long-term debt	10		**78,000**		29,000
			4,753		8,018
			196,343		158,737
Shareholders' equity					
Share capital	11		**970,134**		970,134
Contributed surplus			**35,371**		33,788
Deficit			**(335,830)**		(324,886)
			669,675		679,036
		$	**866,018**	$	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** **March 31, 2015**	Three months ended March 31, 2014
Revenue			
Oil and gas sales		**$ 22,115**	$ 59,555
Royalties		**(4,089)**	(11,529)
Net oil and gas revenue		**18,026**	48,026
Gain (loss) on risk management contracts	13	**2,334**	(5,967)
		20,360	42,059
Expenses			
Production		**15,905**	19,673
Transportation		**781**	1,539
General and administrative		**2,139**	3,115
Depletion and depreciation	7	**13,765**	17,886
Finance costs	14	**480**	432
Stock-based compensation	11	**1,530**	741
Foreign currency exchange gain		**(55)**	(9)
		34,545	43,377
Other income			
Interest income		**6**	29
Loss before income taxes		**(14,179)**	(1,289)
Income taxes			
Current income tax		**30**	18
Deferred income recovery		**(3,265)**	(181)
		(3,235)	(163)
Net and comprehensive loss for the period		**$ (10,944)**	$ (1,126)
Loss per share			
Basic	11	**$ (0.03)**	$ (0.00)
Diluted	11	**$ (0.03)**	$ (0.00)

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Changes in Equity

(unaudited)
(Cdn$ in thousands)

	Three months ended March 31, 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	-	-	(10,944)	(10,944)
Stock-based compensation	-	1,583	-	1,583
Balance - March 31, 2015	**$ 970,134**	**$ 35,371**	**$ (335,830)**	**$ 669,675**

	Three months ended March 31, 2014			
	Share Capital	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance - January 1, 2014	$ 881,949	$ 28,699	$ (351,711)	$ 558,937
Net and comprehensive loss for the period	-	-	(1,126)	(1,126)
Stock-based compensation	-	772	-	772
Shares issued on equity offering	70,225	-	-	70,225
Share issue costs	(2,597)	-	-	(2,597)
Shares issued on exercise of stock options	1,375	-	-	1,375
Transfer to share capital on exercise of stock options	711	(711)	-	-
Balance - March 31, 2014	$ 951,663	$ 28,760	$ (352,837)	$ 627,586

See accompanying notes to consolidated financial statements

BLACKPEARL RESOURCES INC.

Consolidated Statements of Cash Flows

(unaudited) (Cdn$ in thousands)	Note		Three months ended March 31, 2015		Three months ended March 31, 2014
Operating activities					
Net and comprehensive loss for the period		**$**	**(10,944)**	$	(1,126)
Items not involving cash:					
Depletion and depreciation	7		**13,765**		17,886
Accretion of decommissioning liabilities	14		**417**		371
Stock-based compensation	11		**1,530**		741
Foreign exchange loss			**63**		45
Deferred income recovery			**(3,265)**		(181)
Unrealized loss on risk management contracts	13		**11,374**		5,301
Decommissioning costs incurred	9		**(245)**		(204)
Changes in non-cash working capital	14		**11,154**		(4,316)
Cash flow from operating activities			**23,849**		18,517
Financing activities					
Proceeds on issue of common shares, net of costs			**-**		68,129
Proceeds on issue of long-term debt	10		**49,000**		-
Cash flow from financing activities			**49,000**		68,129
Investing activities					
Capital expenditures - exploration and evaluation assets	6		**(2,134)**		(2,544)
Capital expenditures - property, plant and equipment	7		**(40,794)**		(46,755)
Changes in non-cash working capital	14		**(27,279)**		23,328
Cash flow used in investing activities			**(70,207)**		(25,971)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency			**(118)**		(54)
Increase in cash and cash equivalents			**2,524**		60,621
Cash and cash equivalents, beginning of period			**2,918**		8,402
Cash and cash equivalents, end of period		**$**	**5,442**	$	69,023

See accompanying notes to consolidated financial statements

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

1. GENERAL INFORMATION

BlackPearl Resources Inc. (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 months ended March 31, 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 May 6, 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, 2017 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 Instrument: 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

		March 31, 2015		December 31, 2014
Cash at financial institutions	**$**	**5,442**	$	2,918

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of March 31, 2015, US $1.1 million (2014 – US $1.3 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

5. TRADE AND OTHER RECEIVABLES

		March 31, 2015		December 31, 2014
Trade accounts receivable	**$**	**8,688**	$	12,249
Receivables from joint venture partners		**302**		309
Allowance for doubtful accounts		**(285)**		(285)
Net accounts receivable		**8,705**		12,273
Royalty reimbursement from enhanced oil recovery incentive programs		**1,038**		1,038
Receivable from risk management contracts		**4,492**		4,059
Other receivables		**807**		1,097
Total trade and other receivables	**$**	**15,042**	$	18,467

Aging of trade accounts receivables are as follows:

		March 31, 2015		December 31, 2014
Current	**$**	**8,618**	$	12,232
31 to 60 days		**26**		9
61 to 90 days		**32**		8
Over 90 days		**12**		-
	$	**8,688**	$	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	2,134
Change in decommissioning provision	(214)
At March 31, 2015	$ 168,264

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 three 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 three months ended March 31, 2015 the Company capitalized net operating revenues totalling a loss of $1.2 million ($1.3 million loss in the first quarter of 2014). The Company did not capitalize any general and administrative costs related to exploration activities during the three months ended March 31, 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	40,794	-	40,794
Capitalized stock-based compensation	53	-	53
Change in decommissioning provision	11,655	-	11,655
At March 31, 2015	$ 1,222,672	$ 3,496	$ 1,226,168
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	13,720	45	13,765
At March 31, 2015	$ 557,294	$ 2,359	$ 559,653
Net book value			
December 31, 2014	$ 626,596	$ 1,182	$ 627,778
March 31, 2015	$ 665,378	$ 1,137	$ 666,515

During the three months ended March 31, 2015, the Company capitalized borrowing costs of $0.5 million (2014 - $0.1 million) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the three months ended March 31, 2015 (2014 - $Nil).

Property, plant and equipment at March 31, 2015 includes $255.0 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.

The Company performed review tests at March 31, 2015 for any indication of impairment. No assets were considered to be impaired and no impairment was recorded during the three months ended March 31, 2015 (2014 - $Nil).

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	March 31, 2015	December 31, 2014
Trade payables and accrued liabilities	**$ 40,669**	$ 60,065
Payables to joint arrangements	**413**	570
Other payables	**212**	401
	$ 41,294	$ 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 $83.7 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:

		Three months ended March 31, 2015		Year Ended December 31, 2014
Decommissioning liability, beginning of period	**$**	**60,683**	$	55,384
New liabilities recognized		**12,564**		4,261
Liabilities acquired		**-**		470
Reduction in liabilities due to asset dispositions		**-**		(210)
Decommissioning costs incurred		**(245)**		(963)
Change in inflation rate		**(2,888)**		-
Change in discount rate		**1,765**		209
Accretion expense		**417**		1,532
Decommissioning liability, end of period		**72,296**		60,683
Less current portion of decommissioning liability		**(1,082)**		(852)
Non-current portion of decommissioning liability	**$**	**71,214**	$	59,831

10. LONG-TERM DEBT

At March 31, 2015 the Company had credit facilities of $150 million, consisting of a $140 million syndicated revolving line of credit (December 31, 2014 - $140 million) and a non-syndicated operating line of credit of $10 million (December 31, 2014 - $10 million). 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 May 31, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2015. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

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 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.

At March 31, 2015, the Company had $78 million (December 31, 2014 - $29 million) drawn under its existing credit facilities and issued letters of credit in the amount of $20,000 (December 31, 2014 - $20,000); leaving $72 million (December 31, 2014 - $121 million) available to be drawn under these credit facilities.

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 2.2:1 at March 31, 2015 (December 31, 2014 – 2.3:1) and is in compliance with this covenant at March 31, 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 March 31, 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	7,165,000	0.91
Forfeited	(228,334)	3.46
Expired	(30,000)	2.42
Outstanding at March 31, 2015	27,823,001	2.46

Options outstanding and exercisable as at March 31, 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	7,165,000	0.91	4.93	-	-	-
1.51 – 3.00	14,684,001	2.31	3.91	5,701,267	2.33	3.75
3.01 – 4.50	1,896,500	3.68	2.18	1,289,354	3.66	2.15
4.51 – 6.00	3,762,500	5.01	1.14	3,762,500	5.01	1.14
6.01 – 7.66	315,000	6.91	1.19	315,000	6.91	1.19
	27,823,001	2.46	3.65	11,068,121	3.53	2.60

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the three months ended March 31, 2015, 7,165,000 options were granted (2014 – 7,806,000). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	**Three months ended March 31, 2015**	Three months ended March 31, 2014
Risk free interest rate (%)	**0.7**	1.3
Dividend yield (%)	**0.0**	0.0
Expected life (years)	**3.6**	3.6
Expected volatility (%)	**53.6**	50.7
Forfeiture rate (%)	**13.6**	15.1
Weighted average fair value of options	**$ 0.36**	$ 1.03

(d) Stock-based Compensation

	Three months ended March 31, 2015	Three months ended March 31, 2014
Gross stock-based compensation	**$ 1,628**	$ 941
Recoveries from forfeitures	**(45)**	(169)
Net stock-based compensation before capitalization	**1,583**	772
Stock-based compensation capitalized to property, plant and equipment	**(53)**	(31)
Net stock-based compensation	**$ 1,530**	$ 741

(e) Loss per Share

Basic loss per share amounts are calculated by dividing net and comprehensive 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 loss per share:

		Three months ended March 31, 2015		Three months ended March 31, 2014
Net and comprehensive loss	**$**	**(10,944)**	$	(1,126)
Weighted average number of common shares - basic		**327,806**		304,841
Dilutive effect:				
Outstanding options		**-**		1,033
Weighted average number of common shares – diluted		**327,806**		305,874
Basic loss per share	**$**	**(0.03)**	$	(0.00)
Diluted loss per share	**$**	**(0.03)**	$	(0.00)

For the three months ended March 31, 2015, the Company used a weighted average market closing price of $0.94 (2014 - $2.54) per share to calculate the dilutive effect of stock options. For the three months ended March 31, 2015, 22,806,723 weighted average options were anti-dilutive (2014 – 12,286,849) 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)	$ 1,515	$ 1,563	$ 249	$ 202	$ 84	$ -
Electrical service agreement (2)	712	520	119	119	119	2,106
Transportation service agreement (3)	102	135	135	135	135	33
Capital commitments (4)	8,150	-	-	-	-	-
	$ 10,479	$ 2,218	$ 503	$ 456	$ 338	$ 2,139

(1) The Company has 18 months remaining on an operating lease for office space as at March 31, 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 lease obligation, BlackPearl would be required to pay a maximum additional amount of $4.7 million (including an estimate for operating costs) over the next 18 months. At March 31, 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 entered into certain agreements pertaining to the construction of the Onion Lake EOR project.

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at March 31, 2015 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets, accounts payable and accrued 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.

	March 31, 2015		December 31, 2014	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Loans and receivables:				
Cash and cash equivalents	$ 5,442	$ 5,442	$ 2,918	$ 2,918
Trade and other receivables	$ 14,004	$ 14,004	$ 17,429	$ 17,429
Deposits	$ 410	$ 410	$ 427	$ 427
Financial liabilities at fair value through profit or loss:				
Risk management assets	$ 9,254	$ 9,254	$ 20,628	$ 20,628
Financial liabilities				
Financial liabilities at amortized cost:				
Accounts payable and accrued liabilities	$ 41,294	$ 41,294	$ 61,036	$ 61,036
Long-term debt	$ 78,000	$ 78,000	$ 29,000	$ 29,000

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 March 31, 2015, over 58 percent of total accounts receivable are for crude oil sales revenue (December 31, 2014 – 66 percent).

In the first quarter 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 78% (December 31, 2014 – 73%) of the Company's total oil and gas sales in the first quarter of 2015.

At March 31, 2015, the Company had a $1.0 million (December 31, 2014 - $1.0 million) receivable related to the reimbursement of crown royalties as a result of an enhanced oil recovery incentive program from the Alberta government. These amounts are not considered impaired based on the credit worthiness of the Alberta government and the approval the Company has received on its enhanced oil recovery activities.

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 March 31, 2015, the Company had a $4.5 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 March 31, 2015, the Company held $5.4 million (December 31, 2014 - $2.9 million) in cash at various major financial institutions throughout Canada and the USA. At March 31, 2015, one Canadian financial institution held over 79% (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 March 31, 2015, the Company had $72 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	$41,243	-	-
Long-term debt	-	-	$78,000

(iii) Interest Rate Risk

The Company is exposed to interest rate risk related to interest expense on its revolving credit facility due to the floating interest rate charged on advances. For the period ended March 31, 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 $16,000 lower. In addition, the Company is exposed to interest rate risk on its excess cash balances. As at March 31, 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 $15,000 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 March 31, 2015, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at March 31, 2015, the Company held US $1.1 million (December 31, 2014 - US $1.3 million) cash and cash equivalents and US $44,000 (December 31, 2015 - US $35,000) accounts payable and accrued liabilities.

As at March 31, 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 period would have been approximately $106,000 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 5% (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 activities.

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 March 31, 2015		Three months ended March 31, 2014
Realized gain (loss) on risk management contracts	**$**	**13,708**	$	(666)
Unrealized gain (loss) on risk management contracts		**(11,374)**		(5,301)
Gain (loss) on risk management contracts	**$**	**2,334**	$	(5,967)

The table below summarizes the Company's commodity contracts as at March 31, 2015:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	2,500 bbls/d	April 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 61.00/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI	CDN$ 80.00/bbl	Sold Call Swaption(1)
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	USD$ WTI	USD$ 65.00/bbl	Sold Call Swaption(1)

(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.

Subsequent to March 31, 2015, the Company entered into the following commodity contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 62.25/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS	CDN$ 72.00/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

14. SUPPLEMENTARY INFORMATION

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

		Three months ended March 31, 2015		Three months ended March 31, 2014
Cash interest paid	**$**	**583**	$	150
Cash taxes paid	**$**	**30**	$	18

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

		Three months ended March 31, 2015		Three months ended March 31, 2014
Gross interest and financing charges	**$**	**583**	$	150
Capitalized interest and financing charges		**(520)**		(89)
Net interest and financing charges		**63**		61
Accretion of decommissioning liabilities		**417**		371
Finance costs	**$**	**480**	$	432

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

		Three months ended March 31, 2015		Three months ended March 31, 2014
Changes in non-cash working capital:				
Trade and other receivables	**$**	**3,425**	$	(2,579)
Inventory		**100**		(208)
Prepaid expenses and deposits		**37**		151
Accounts payable and accrued liabilities		**(19,687)**		21,648
	$	**(16,125)**	$	19,012
Relating to:				
Operating activities	**$**	**11,154**	$	(4,316)
Investing activities		**(27,279)**		23,328
Changes in non-cash working capital	**$**	**(16,125)**	$	19,012