

BLACKPEARL RESOURCES INC.

Management's Discussion and Analysis

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the three and six months ended June 30, 2017. These results are being compared with the three and six months ended June 30, 2016. The MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017, together with the accompanying notes and with the Company's annual MD&A for the year ended December 31, 2016.

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

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

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

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

Non-GAAP Financial Measures

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

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

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

	2017		2016	Six months ended June 30	
(\$000s)	Q2	Q1	Q2	2017	2016
Cash flow from operating activities ⁽¹⁾	15,080	14,786	7,184	29,866	10,971
Decommissioning costs incurred	83	42	369	125	516
Changes in non-cash working capital related to operations	(984)	(1,904)	3,944	(2,888)	3,288
Adjusted funds flow ⁽²⁾	14,179	12,924	11,497	27,103	14,775

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

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

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

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

(\$000s)	June 30, 2017	December 31, 2016
Long-term debt ⁽¹⁾	72,320	-
Add (deduct) working capital:		
Cash and cash equivalents	(43,441)	(5,368)
Trade and other receivables	(14,284)	(13,391)
Inventory	(65)	(46)
Prepaid expenses and deposits	(1,822)	(705)
Fair value of risk management assets	(6,636)	-
Accounts payable and accrued liabilities	21,835	17,950
Current portion of decommissioning liabilities	733	644
Fair value of risk management liabilities	-	5,507
Net debt ⁽²⁾	28,640	4,591

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

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

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

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

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

The effective date of this MD&A is August 9, 2017.

OVERVIEW

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

BlackPearl’s current core properties are:

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

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

2017 SIGNIFICANT EVENTS

- On June 30, 2017, the Company issued \$75 million aggregate principal amount of senior secured second lien notes to Prudential Capital Group. The senior secured notes were issued at par and bear interest at 8.00% per year, payable quarterly in arrears, and mature on June 30, 2020. In conjunction with the issuance of the senior secured notes, the Company also amended its existing senior credit facilities with its lending syndicate. The amendments include an increase in the borrowing base amount from \$117.5 million to \$120 million. Proceeds from the issue of the senior secured notes and our existing senior credit facilities will be used to fund the construction of the second phase of our Onion Lake thermal project and for general corporate purposes.
- During the first quarter of 2017, the Company commenced construction of the second 6,000 bbls/d phase of the Onion Lake thermal project. Total estimated capital costs for the project are approximately \$185 million and the project is expected to be completed in mid-2018 with peak production rates by mid-year 2019. As of June 30, 2017, approximately 80% of the module fabrications for the second phase plant facilities were complete and we commenced drilling the steam injector and producer wells.
- In the first half of 2017, WTI oil prices averaged US\$50.10 per bbl compared to US\$39.52 per bbl in the first half of 2016.
- During the second quarter of 2017, oil and gas production averaged 10,386 boe/d; a 7% increase compared to the same period in 2016. The increase was mainly attributable to the first phase of the Onion Lake thermal project and the re-start of the ASP flood at Mooney. During the first half of 2017, oil and gas production averaged 10,568 boe/d.
- Capital expenditures during the first half were \$66.8 million, with approximately \$59.5 million spent at the Onion Lake thermal project related to construction of the second phase of the project, \$3.7 million spent at John Lake related to the drilling of two horizontal heavy oil wells, \$1.7 million at Mooney related to bringing shut-in production back online and \$1.9 million spent in other areas. The Company also completed dispositions of non-producing properties for proceeds totaling \$3.4 million during the first half of the year.
- Oil and gas sales during the first half of 2017 increased 81% to \$75 million, cash flow from operating activities were \$30 million and adjusted funds flow (a non-GAAP measure) were \$27 million. For the six months ended June 30, 2017, the Company recognized net income of \$16 million.

- During the first half of 2017, 302,007 common shares were issued pursuant to the exercise of stock options which generated net proceeds of \$0.3 million for the Company. The Company did not undertake any equity issuances during the first half of 2017.

SELECTED QUARTERLY INFORMATION

	2017				2016		2015	
(\$000s, except where noted)	<u>Jun 30</u>	<u>Mar 31</u>	<u>Dec 31</u>	<u>Sep 30</u>	<u>Jun 30</u>	<u>Mar 31</u>	<u>Dec 31</u>	<u>Sep 30</u>
Production (boe/d) ⁽¹⁾	10,386	10,753	10,479	10,951	9,698	9,166	9,521	7,478
Oil and gas sales	37,702	37,204	35,360	32,367	28,318	13,021	22,630	20,814
Oil sales (\$/bbl)	41.93	40.75	38.83	34.15	34.44	16.77	27.65	35.02
Gas sales (\$/mcf)	2.58	2.50	2.90	2.10	1.29	1.77	2.91	2.88
Oil and gas sales (\$/boe)	41.65	40.48	38.61	33.87	34.03	16.67	27.45	34.05
Production & transportation costs	15,926	16,233	13,550	13,603	12,246	11,736	15,666	12,843
Production costs (\$/boe)	14.97	15.00	12.11	12.13	13.23	12.35	17.77	20.04
Transportation costs (\$/boe)	2.62	2.67	2.69	2.11	1.48	2.68	1.23	0.97
Gain (loss) on risk management contracts								
Realized	(34)	342	578	2,137	1,958	6,120	10,334	7,940
Unrealized	5,724	5,569	(5,676)	(538)	(8,597)	(472)	1,778	11,826
Net income (loss)	8,318	7,814	(2,217)	556	(8,945)	(9,322)	(31,172)	5,402
Per share, basic and diluted (\$)	0.02	0.02	(0.01)	0.00	(0.03)	(0.03)	(0.09)	0.01
Capital expenditures	53,434	13,356	6,150	1,753	945	2,077	1,665	7,870
Adjusted funds flow ⁽²⁾	14,179	12,924	15,798	14,202	11,497	3,278	10,898	10,156
Cash flow from operating activities	15,080	14,786	15,079	16,441	7,184	3,787	12,179	14,216
Long-term debt	72,320	-	-	67,000	80,000	86,000	88,000	97,000
Total assets (end of period)	822,325	737,735	732,404	773,206	782,591	795,336	808,344	861,107
Shares outstanding (000s)	336,251	336,196	335,949	335,647	335,647	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	336,226	336,157	335,733	335,646	335,641	335,638	335,638	335,638
Diluted	339,019	340,700	340,686	337,959	335,641	335,638	335,638	335,638

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

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

Fluctuations in quarterly oil and gas sales and net income (loss) over the last eight quarters are primarily attributable to the volatility in crude oil prices and changes in sales volumes from new drilling activity, partially offset by natural declines in production. Production volumes in Q4 2015 increased as a result of the start-up of commercial

production from the first phase of the Onion Lake thermal project. The net loss incurred in Q4 2015 is mainly attributable to an impairment charge of \$33 million taken on our Mooney cash generating unit (“CGU”).

BUSINESS ENVIRONMENT

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

Commodity Prices

	YTD		2017		2016			
	2017	2016	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices								
West Texas Intermediate (WTI) (US\$/bbl)	50.10	39.52	48.29	51.91	49.29	44.94	45.59	33.45
Western Canadian Select (WCS) (Cdn\$/bbl)	49.66	33.96	49.96	49.36	46.62	41.02	41.61	26.31
Differential – WCS/WTI (US\$/bbl)	12.86	14.02	11.14	14.61	14.34	13.51	13.30	14.32
Differential - WCS/WTI (%)	25.7%	35.5%	23.1%	28.1%	29.1%	30.1%	29.2%	42.8%
Average Natural Gas Prices								
AECO gas (Cdn\$/GJ)	2.60	1.53	2.64	2.55	2.93	2.20	1.33	1.74
Average Foreign Exchange (US\$ per Cdn\$1)	0.750	0.751	0.743	0.756	0.750	0.766	0.776	0.727

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 during the second quarter of 2017 compared to the first quarter; however, prices remain higher than the comparable periods in 2016. WTI oil prices averaged US\$48.29 per bbl in the second quarter of 2017 compared to US\$51.91 per bbl in the first quarter of 2017 and US\$45.59 per bbl in the second quarter of 2016. The decline in second quarter WTI oil prices has been attributed to higher production, particularly in the US and continuing high inventory levels. For the first six months of 2017 WTI oil prices averaged US\$50.10 per bbl which is up from US\$39.52 per bbl in the same period in 2016.

The heavy oil differential (WTI oil prices compared to WCS oil prices) improved in the second quarter of 2017. Heavy oil differentials averaged US\$11.14 per bbl in the second quarter of 2017 compared to US\$14.61 per bbl in the first quarter of 2017. Heavy oil differentials narrowed in the second quarter of 2017 as a result of temporarily shut-in heavy oil production in Canada and decreased US imports of heavier grades of oil from OPEC countries due to their decision to reduce oil output, resulting in greater demand for Canadian heavy oil.

Natural gas prices increased in the first half of 2017 averaging \$2.60/GJ compared to \$1.53/GJ in the same period in 2016. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current revenues. However, we do consume relatively large amounts of gas in our Blackrod pilot operations and at our Onion Lake thermal project, therefore, fluctuations in natural gas prices can have a significant effect on our costs in these areas.

Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by reference to US benchmark prices. The Canadian dollar was fairly consistent against the US dollar in the first half of 2017 compared to the same period in 2016. The exchange rate between the Canadian dollar and the US dollar averaged Cdn\$1 = US\$0.75 during the first half of 2017 and 2016. More recently, the Canadian dollar has strengthened relative to the US dollar which will negatively impact our future revenues and cash flows.

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

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

Key variable	Change (\$)	\$000s
West Texas Intermediate (WTI) (US\$/bbl)	1.00	851
Realized crude oil price (Cdn\$/bbl)	1.00	1,489
US \$ to Canadian \$ exchange rate	0.01	423

(1) This analysis assumes current royalty rates and operating costs, no changes in working capital and includes the impact of realized risk management contracts.

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

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

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
Daily production/sales volumes					
Oil (bbls/d)	9,843	10,105	9,004	9,973	8,723
Bitumen – Blackrod (bbls/d) ⁽²⁾	437	<u>542</u>	<u>553</u>	489	<u>568</u>
Combined (bbls/d)	10,280	10,647	9,557	10,462	9,291
Natural gas (Mcf/d)	633	<u>638</u>	<u>847</u>	635	<u>846</u>
Total production (boe/d) ⁽¹⁾	10,386	10,753	9,698	10,568	9,432
Product pricing (excluding risk management activities) ⁽²⁾					
Oil (\$/bbl)	41.93	40.75	34.44	41.33	25.89
Natural gas (\$/Mcf)	2.58	<u>2.50</u>	<u>1.29</u>	2.54	<u>1.53</u>
Combined (\$/boe) ⁽¹⁾	41.65	40.48	34.03	41.06	25.63
Sales (\$000s) ⁽²⁾					
Oil and gas sales – gross	37,702	37,204	28,318	74,906	41,339
Royalties	(5,317)	<u>(5,422)</u>	<u>(3,813)</u>	(10,739)	<u>(5,158)</u>
Oil and gas revenues – net ⁽³⁾	32,385	31,782	24,505	64,167	36,181

(1) Natural gas production converted at 6:1 (for boe figures).

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

(3) Excludes deferred consideration amount recognized during the period.

Oil and natural gas sales increased 33% in the second quarter of 2017 to \$37.7 million from \$28.3 million in the same period in 2016. The increase in oil and gas sales is attributable to a 22% increase in our average realized sale price and a 7% increase in production volumes (on a boe basis) in the second quarter of 2017 compared to the same period in 2016.

Higher WTI crude oil prices and narrower heavy oil differentials contributed to an increase in our realized crude oil sales prices in the second quarter of 2017 compared to the same period in 2016. Our average oil wellhead sales price in the second quarter of 2017, prior to the impact of risk management activities, was \$41.93 per bbl compared with \$34.44 per bbl in the same period in 2016.

Production growth in the first half of 2017 compared to the same period in 2016 is mainly attributable to the first phase of our Onion Lake thermal project. During the first half of 2017, production from this project averaged 5,998 bbls/d compared with 4,737 bbls/d during the same period in 2016. Production from the Onion Lake thermal facility was temporarily impacted in Q2 2017 by a planned facility turnaround and inspection which began in late June. The three week turnaround was planned to coincide with drilling some of the phase two wells to reduce the amount of facility downtime. Phase one production is expected to return to full rates in August or early September.

With the improvement in crude oil prices, during the first half of 2017 we selectively brought back on production certain shut-in wells at Onion Lake and re-initiated a portion of the ASP flood at Mooney. Production from the re-initiated ASP flood at Mooney contributed to a 54% increase in oil production in Q2 2017 from the Mooney field compared to Q2 2016. We still have approximately 500 bbls of oil per day currently shut-in at Onion Lake. The Company continues to evaluate the shut-in production at Onion Lake to determine if any would become economic at current oil prices based on our internal payout metrics. We expect oil prices would have to improve to US\$55 to US\$60 per bbl before we would consider putting some of these shut-in wells back on production.

On a boe basis, 99% of the Company's oil and natural gas production in the second quarter of 2017 was heavy oil or bitumen. The Onion Lake area accounted for 76% of total production in the second quarter of 2017.

	2017		2016	Six months ended June 30	
Production by area (boe/d)	Q2	Q1	Q2	2017	2016
Onion Lake - thermal	5,816	6,182	5,221	5,998	4,737
Onion Lake - conventional	2,087	2,147	2,138	2,117	2,185
Mooney	1,103	942	714	1,023	878
John Lake	801	808	870	804	865
Blackrod	437	542	553	489	568
Other	142	132	202	137	199
Total production	10,386	10,753	9,698	10,568	9,432

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. A second pilot well pair was drilled and put on production in 2013. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. The original SAGD pilot well was shut-in in August 2015. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. During the first half of 2017, the pilot well produced an average of 489 bbls/d of bitumen and the net revenues capitalized in the first half of 2017 were \$0.2 million (\$0.6 million loss in the first half of 2016).

Risk Management Activities

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

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the fair values of our outstanding risk management contracts. The Company had a net gain of \$5.7 million on its risk management contracts during the second quarter of 2017, consisting of a \$34,000 realized loss on the contracts and an unrealized gain of \$5.7 million.

	2017		2016	Six months ended June 30	
(\$000s, except per boe)	Q2	Q1	Q2	2017	2016
Realized gain (loss) on risk management contracts	(34)	342	1,958	308	8,078
Per boe (\$)	(0.04)	0.37	2.35	0.17	5.01
Unrealized gain (loss) on risk management contracts	5,724	5,569	(8,597)	11,293	(9,069)

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

Subject of Contract	Volume	Term	Reference	Strike Price	Type
<u>2017</u>					
Oil	500 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 54.30/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 53.10/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 53.00/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 52.75/bbl	Swap
Oil	500 bbls/d	July 1 to December 31	US\$ WCS	US\$ 40.15/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 50.00/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	CDN\$ WCS	CDN\$ 49.50/bbl	Swap
Oil	1,000 bbls/d	July 1 to December 31	US\$ WTI	US\$ 60.00/bbl	Sold Call
<u>2018</u>					
Oil	2,000 bbls/d	January 1 to June 30	CDN\$ WCS	CDN\$ 49.55/bbl	Swap
Oil	1,000 bbls/d	January 1 to June 30	US\$ WTI	US\$ 45.00/bbl to 57.75/bbl	Collar
Oil	1,500 bbls/d	January 1 to June 30	US\$ WTI	US\$ 40.00/bbl to 50.00/bbl	Collar
Oil	2,200 bbls/d	July 1 to December 31	US\$ WTI	US\$ 40.00/bbl to 51.00/bbl	Collar
Oil	500 bbls/d	January 1 to December 31	US\$ WTI	US\$ 70.00/bbl	Sold Call

At June 30, 2017, these contracts had a net fair value of \$5.3 million in a derivative asset position. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate \$9.5 million increase in fair value. A 10% increase to the oil price used to calculate the fair value of these contracts would result in an approximate \$11.8 million decrease in fair value.

Royalties

	2017			Six months ended	
	Q2	Q1	Q2	2017	2016
Royalties (\$000s)	5,317	5,422	3,813	10,739	5,158
Per boe (\$)	5.87	5.90	4.58	5.89	3.20
As a percentage of oil and gas sales	14%	15%	13%	14%	12%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased as well as overriding royalties paid to third parties as a result of contractual arrangements. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, the majority of the royalties are paid to Indian Oil and Gas Canada on behalf of the Onion Lake Cree Nation. Royalty rates are generally dependent on commodity prices, oil quality and well productivity. Enhanced oil recovery projects (such as our Onion Lake thermal project) typically pay lower royalties until the project recovers its capital costs and then royalty rates increase.

Royalties were \$5.3 million in the second quarter of 2017, an increase from \$3.8 million in the same period in 2016. The increase in royalties is primarily attributable to higher revenues in 2017. Royalties as a percentage of oil and gas sales increased to 14% in the second quarter of 2017 from 13% in the same period in 2016. Higher oil prices realized in the second quarter of 2017 resulted in higher royalties as a percentage of oil and gas sales. The increase in royalty rates in 2017 is also attributable to the sale, in late 2016, of a 1.75% royalty on substantially all of our current and future Onion Lake production.

Transportation Costs

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
<i>Conventional Production</i>					
Transportation costs (\$000s)	605	407	127	1,012	445
Per boe (\$)	1.61	1.12	0.36	1.37	0.59
<i>Thermal Production</i>					
Transportation costs (\$000s)	1,769	2,043	1,106	3,812	2,881
Per boe (\$)	3.34	3.67	2.33	3.51	3.34
<i>Total Production</i>					
Transportation costs (\$000s)	2,374	2,450	1,233	4,824	3,326
Per boe (\$)	2.62	2.67	1.48	2.64	2.06

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Costs to ship oil emulsion to a treating facility before it is sold are included in production expenses rather than transportation costs. Transportation costs increased in the second quarter of 2017 to \$2.4 million from \$1.2 million in the same period of 2016. The increase in transportation costs is primarily attributable to increased production from the first phase of the Onion Lake thermal project which ships mostly clean marketable crude oil. Transportation costs in Q2 2017 were similar to Q1 2017 costs.

Production Costs

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
<i>Conventional Production</i>					
Production costs (\$000s)	7,941	8,858	6,400	16,799	11,950
Per boe (\$)	21.11	24.43	17.92	22.74	15.91
<i>Thermal Production</i>					
Production costs (\$000s)	5,611	4,925	4,613	10,536	8,706
Per boe (\$)	10.60	8.85	9.71	9.71	10.10
Energy costs	4.16	4.27	2.47	4.22	3.53
Non-energy costs	6.44	4.58	7.23	5.49	6.57
<i>Total Production</i>					
Production costs (\$000s)	13,552	13,783	11,013	27,335	20,656
Per boe (\$)	14.97	15.00	13.23	14.98	12.80

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

Total production costs increased 23% in the second quarter of 2017 to \$13.6 million from \$11.0 million in the same period in 2016. On a per boe basis, total production costs increased 13% in the second quarter of 2017 to \$14.97 per boe from \$13.23 per boe in the same period in 2016.

Conventional production costs increased in the second quarter of 2017 compared to the same period in 2016. The re-initialization of a portion of the ASP flood at Mooney resulted in an increase in chemical and injection costs during the second quarter of 2017. Conventional production costs decreased in the second quarter of 2017 compared to the first quarter of 2017. During the first quarter of 2017, we incurred increased workover costs on the wells we restarted at Mooney and Onion Lake, whereas during the second quarter of 2017, workover activities returned to more normal levels.

The increase in thermal production costs in the second quarter of 2017 compared to the same period in 2016 is primarily attributable to higher natural gas consumption costs as a result of higher natural gas prices in 2017. In

addition, thermal production costs increased in the second quarter of 2017 compared to the first quarter of 2017 primarily due to costs related to a planned facility turnaround and inspection at Onion Lake that were incurred at the end of June.

Operating Netback ^{(1) (2) (3)}

Three months ended

	Q2 2017		Q1 2017		Q2 2016	
	\$000s	\$/boe	\$000s	\$/boe	\$000s	\$/boe
Oil and gas sales	37,702	41.65	37,204	40.48	28,318	34.03
Royalties	5,317	5.87	5,422	5.90	3,813	4.58
Transportation costs	2,374	2.62	2,450	2.67	1,233	1.48
Production costs	13,552	14.97	13,783	15.00	11,013	13.23
Operating netback before realized risk management contracts	16,459	18.19	15,549	16.91	12,259	14.74
Realized gain on risk management contracts	(34)	(0.04)	342	0.37	1,958	2.35
Operating netback after realized risk management contracts	16,425	18.15	15,891	17.28	14,217	17.09

Six months ended

	June 2017		June 2016	
	\$000s	\$/boe	\$000s	\$/boe
Oil and gas sales	74,906	41.06	41,339	25.63
Royalties	10,739	5.89	5,158	3.20
Transportation costs	4,824	2.64	3,326	2.06
Production costs	27,335	14.98	20,656	12.80
Operating netback before realized risk management contracts	32,008	17.55	12,199	7.57
Realized gain on risk management contracts	308	0.17	8,078	5.01
Operating netback after realized risk management contracts	32,316	17.72	20,277	12.58

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

(2) Production used when calculating operating netback is determined by the number of days in the period multiplied by average daily production less capitalized production at Blackrod as disclosed in the Oil and Gas, Oil and Gas Pricing and Oil and Gas Sales section of this MD&A. (Q2 2017 – 9,948 boe/d; Q1 2017 – 10,211 boe/d; Q2 2016 – 9,145 boe/d; Six months ended June 2017 – 10,079 boe/d; Six months ended June 2016 – 8,864 boe/d).

(3) Excludes deferred consideration amount recognized during the period.

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, before realized gains on risk management activities, increased in the second quarter of 2017 to \$18.19 per boe from \$14.74 per boe in the same period in 2016. The increase is primarily attributable to the increase in realized crude oil prices, partially offset by higher royalties and production costs.

General and Administrative Expenses (G&A)

	2017		2016	Six months ended June 30	
(\$000s, except per boe)	Q2	Q1	Q2	2017	2016
Gross G&A expense	2,033	3,023	2,009	5,056	4,138
Operator recoveries	(219)	(236)	(209)	(455)	(439)
Net G&A expense	1,814	2,787	1,800	4,601	3,699
Per boe (\$)	2.00	3.03	2.16	2.52	2.29

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Q2 2017 general and administrative costs were comparable to Q2 2016. The increase in gross G&A expenses in the first half of 2017 compared to the same period in 2016 reflects higher staff compensation costs in 2017. As oil prices stabilized during 2017, previous salary reductions were rescinded and performance incentive payments to staff were made during the first quarter of the year.

Stock-Based Compensation

	2017		2016	Six months ended June 30	
(\$000s, except per boe)	Q2	Q1	Q2	2017	2016
Gross stock-based compensation	566	570	711	1,136	1,889
Recoveries from forfeitures	(21)	(5)	-	(26)	(48)
Net stock-based compensation	545	565	711	1,110	1,841
Per boe (\$)	0.60	0.62	0.85	0.61	1.14

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

The decrease in gross stock-based compensation in the first half of 2017 compared to the same period in 2016 is primarily attributable to a decrease in the weighted average number of options outstanding during 2017. In the first half of 2017, 302,007 options were exercised, 1,867,000 options were granted, 179,999 options were forfeited and 1,279,500 options expired. Based on stock options and RSUs outstanding as at June 30, 2017, the Company has an unamortized stock based compensation expense of approximately \$3.8 million, of which \$1.2 million is expected to be expensed in the remainder of 2017, \$1.4 million in 2018, \$1.0 million in 2019 and \$0.2 million in 2020.

Finance Costs

	2017		2016	Six months ended June 30	
(\$000s)	Q2	Q1	Q2	2017	2016
Gross interest & financing charges	632	162	918	794	1,753
Capitalized interest and financing charges	(272)	-	-	(272)	-
Net interest and financing charges	360	162	918	522	1,753
Accretion of decommissioning liabilities	390	387	361	777	727
Total finance costs	750	549	1,279	1,299	2,480

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

The decrease in gross interest and financing charges in the second quarter of 2017 compared to the same period in 2016 is primarily attributed to lower weighted average debt outstanding in the second quarter of 2017. The increase in interest and financing charges in the second quarter of 2017 compared to the first quarter of 2017 is the result of higher loan advances on our credit facilities during the second quarter.

During the first six months of 2017 we incurred slightly lower interest rates charged on amounts borrowed under our credit facilities. The average interest rate on advances under the Company's credit facilities was 3.4% in the first half of 2017 compared to 3.6% in the first half of 2016. This does not include standby fees charged on unutilized amounts of the credit facilities. Our credit facilities are floating rate debt, so the interest rate charged is based on

general market conditions. Additionally, the interest rate charged on our credit facilities is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). The interest rate charged on our credit facilities debt is expected to be 3.5 – 4.0% for the remainder of 2017 (assuming no other changes in market conditions) as a result of carrying a higher debt to EBITDA ratio. We have not entered into any financial instruments to fix the interest rate on our debt.

In addition, gross interest and financing charges will increase during the remainder of the year as a result of the Company's recent issuance of \$75 million of senior secured second lien notes, which bear interest at 8.00% per year.

During the second quarter of 2017 we capitalized \$0.3 million in interest charges related to debt incurred for the construction of the second phase of the Onion Lake thermal project. During 2016 we did not capitalize any interest charges.

Depletion and Depreciation

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
Depletion and depreciation (\$000s)	10,754	10,953	10,773	21,707	21,405
Per boe (\$)	11.88	11.92	12.95	11.90	13.27

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. On a boe basis, depletion and depreciation expense decreased to \$11.88 per boe in the second quarter of 2017 compared to \$12.95 per boe in the same period in 2016. The decrease in depletion and depreciation on a boe basis is primarily attributable to a higher proportion of our production generated from the Onion Lake thermal project in the second quarter of 2017. The depletion rate on this project is below \$10 per boe which is lower than the depletion rates for our other producing areas.

There were no impairment losses or reversals recorded for the six months ended June 30, 2017. However, declines in forecast commodity prices could reduce reserve values and result in the recognition of future asset impairments. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Income Taxes

BlackPearl did not pay cash income taxes in the first six months of 2017 and does not expect to pay income taxes during the remainder of 2017 as we have sufficient tax pools to shelter expected income. In addition, due to a change in the amount of previously unrecognized deferred tax assets, no net deferred tax provision was recorded for the first six months of 2017.

RESULTS FROM OPERATIONS

	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
Net income (loss) (\$000s)	8,318	7,814	(8,945)	16,132	(18,267)
Per share, basic (\$)	0.02	0.02	(0.03)	0.05	(0.05)
Per share, diluted (\$)	0.02	0.02	(0.03)	0.05	(0.05)

For the quarter ended June 30, 2017, the Company recognized net income of \$8.3 million compared to a net loss of \$8.9 million in the same period in 2016. The increase in net income in 2017 is primarily a result of increased revenue from higher realized wellhead prices and an increase in unrealized gains on risk management contracts partially offset by higher royalties and production costs.

(\$000s)	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
Cash flow from operating activities	15,080	14,786	7,184	29,866	10,971
Adjusted funds flow ⁽¹⁾	14,179	12,924	11,497	27,103	14,775

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

Adjusted funds flow increased 23% to \$14.2 million during the second quarter of 2017 compared to \$11.5 million in the same period in 2016. The increase in adjusted funds flow in 2017 is primarily a result of higher realized wellhead prices partially offset by higher royalties and production costs.

Cash flow from operating activities differs from adjusted funds flow principally due to the inclusion of decommissioning costs incurred and changes in non-cash working capital. For the three months ended June 30, 2017, cash flow from operating activities was higher than adjusted funds flow due to changes in non-cash working capital of \$1.0 million.

LIQUIDITY AND CAPITAL RESOURCES

(\$000s)	June 30, 2017	December 31, 2016
Working capital deficiency (surplus)	(43,680)	4,591
Long-term debt	72,320	-
Net debt ⁽¹⁾	28,640	4,591

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

On June 30, 2017, the Company issued \$75 million aggregate principal amount of senior secured second lien notes to Prudential Capital Group. The senior secured notes were issued at par and bear interest at 8.00% per year, payable quarterly in arrears, and mature on June 30, 2020. The proceeds from the senior secured notes will be used, in part, to fund the expansion of our Onion Lake thermal project in Saskatchewan. The senior secured notes are secured by substantially all of the assets of the Company on a second priority basis, subordinate only to the senior credit facilities. The Company may redeem the senior secured notes at any time at a price equal to par, plus a “make-whole” premium and any accrued interest. At June 30, 2017, the carrying value of the senior secured notes, net of deferred financing costs, was \$72.3 million.

In conjunction with the issuance of the senior secured second lien notes, the Company also amended its existing credit facilities with its lending syndicate. The amendments include an increase in the borrowing base amount from \$117.5 million to \$120 million. The lenders previously agreed to extend the revolving period to May 27, 2018, which may be extended in the future at the discretion of the lenders. If the revolving period is not extended, any balance owing on the facilities would be required to be repaid by May 27, 2019. The pricing grid used to calculate the interest rates charged on the loans and stand-by fees remains unchanged. The next borrowing base review is scheduled to occur by November 30, 2017.

At June 30, 2017, the Company had working capital of \$43.7 million, no amounts drawn on its \$120 million credit facilities and had issued letters of credit in the amount of \$20,000; leaving \$120 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities (“Borrowing Base”) is re-determined at least twice a year and is based on the Company’s oil and gas reserves, the lending institution’s forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference.

The Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital is defined as current assets, as indicated on the Company’s consolidated balance sheet, plus any undrawn amount on the senior credit facilities compared to current liabilities from the Company’s consolidated balance sheet. In

addition, amounts related to risk management contracts are excluded from the calculation of current assets and current liabilities. The Company had a working capital ratio of 7.8:1 at June 30, 2017 (December 31, 2016 – 7.2:1).

(\$000s, except working capital ratio)	June 30, 2017	December 31, 2016
Current assets per consolidated financial statements	66,248	19,510
Add: amount available to be drawn on credit facilities	120,000	117,500
Less: current risk management assets	(6,636)	-
Current assets for working capital ratio	179,612	137,010
Current liabilities per consolidated financial statements	22,933	24,505
Less: current risk management liabilities	-	(5,507)
Current liabilities for working capital ratio	22,933	18,998
Working capital ratio	7.8	7.2

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

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

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

At June 30, 2017, there were 336,250,902 common shares issued and outstanding. In the first half of 2017 the Company issued 302,007 common shares for net proceeds of \$0.3 million pursuant to the exercise of stock options.

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

CAPITAL EXPENDITURES

Capital spending during the second quarter of 2017 was \$53.4 million, an increase from \$1.0 million during the same period in 2016. The majority of the capital spending during the second quarter were related to the construction for the second phase of the Onion Lake thermal project.

(\$000s)	2017		2016	Six months ended June 30	
	Q2	Q1	Q2	2017	2016
Land	3,157	1,865	325	5,022	442
Seismic	42	-	-	42	(5)
Drilling and completion	1,787	3,781	70	5,568	1,534
Equipment and facilities	48,446	7,707	550	56,153	1,044
Other	2	3	-	5	7
Total	53,434	13,356	945	66,790	3,022
Property acquisitions	-	-	-	-	-
Total capital expenditures	53,434	13,356	945	66,790	3,022
Proceeds on disposition	-	(3,421)	-	(3,421)	-
Net capital expenditures	53,434	9,935	945	63,369	3,022

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 June 30, 2017. These obligations are expected to be funded from cash flow from operating activities and the Company's credit facilities.

(\$000s)	2017	2018	2019	2020	2021	Thereafter
Operating leases ⁽¹⁾	493	912	703	560	545	-
Electrical service agreement ⁽²⁾	474	585	119	119	119	1,868
Transportation service agreement ⁽³⁾	68	135	135	33	-	-
Decommissioning liabilities ⁽⁴⁾	519	428	347	8,992	1,651	62,802
Capital commitments ⁽⁵⁾	18,340	5,000	5,000	-	-	-
Long-term debt ⁽⁶⁾	-	-	-	75,000	-	-
Interest payments on long-term debt ⁽⁶⁾	1,500	7,500	6,000	3,000	-	-
Total	21,394	14,560	12,304	87,704	2,315	64,670

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

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

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

(4) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were \$74.7 million as at June 30, 2017. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

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

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at June 30, 2017 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts use level 2 valuation methods and are determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

See the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017 for details on the risks associated with these financial instruments including credit risk, liquidity risk, interest rate risk, foreign currency exchange risk and commodity price risk.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the period ended June 30, 2017 or 2016. We do utilize various operating leases in our normal course of business as disclosed under Contractual Obligations and Commitments.

RELATED-PARTY TRANSACTIONS

There was no significant related-party transactions during the period ended June 30, 2017 or 2016 except for key management compensation.

OUTSTANDING SHARE DATA, STOCK OPTIONS AND RESTRICTED SHARE UNITS

As at August 9, 2017, the Company had 336,267,235 common shares outstanding, 26,840,496 stock options outstanding and 1,710,000 restricted share units outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at August 9, 2017, the Company had not drawn any amounts under its existing senior credit facilities and had issued letters of credit in the amount of \$20,000; leaving \$119,980,000 available to be drawn under these credit facilities. The Company had \$75,000,000 outstanding on its senior secured second lien notes on August 9, 2017.

PROPOSED TRANSACTIONS

As of August 9, 2017, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the interim consolidated financial statements in accordance with IFRS requires that management use judgement and make estimates and assumptions regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the interim consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Further information on the Company's critical accounting estimates can be found in the notes to the annual consolidated financial statements and annual MD&A for the year ended December 31, 2016. There have been no significant changes to the Company's critical accounting estimates as of June 30, 2017. Additional disclosure has been provided on the sale of a royalty interest in note 10 of the Company's unaudited consolidated financial statements for the three and six months ended June 30, 2017.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

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

Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

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

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

RISK FACTORS

Please refer to the Company's annual MD&A and Annual Information Form for the year ended December 31, 2016 for a discussion of the risks and uncertainties associated with the Company's activities. Additional risk factors identified in 2017 include the following:

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

CONTROL CERTIFICATION

Management reported on its disclosure controls and procedures and the design of its internal controls over financial reporting ("ICFR") in the annual MD&A for the year ended December 31, 2016. There have been no changes to ICFR in the six months ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

OUTLOOK

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

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

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

Our plan for the remainder of 2017 is relatively unchanged with the focus being the expansion of the Onion Lake thermal project with a target completion date of mid-2018. We are planning to spend between \$195 and \$200 million on capital projects, up from our previous guidance of \$185 and \$190 million. The increase in capital spending is the result of adjusting the timing of expenditures on the Onion Lake thermal expansion.

The capital program is expected to be funded from a combination of our anticipated adjusted funds flow, proceeds from the recent issuance of the \$75 million senior secured second lien notes and our undrawn senior credit facilities. Adjusted funds flow is expected to be between \$52 and \$57 million, down from our previous guidance of \$55 to \$60 million. The decrease in adjusted funds flow is primarily attributable to lower forecast oil prices than what we used in previous guidance updates. For the remainder of the year we have assumed a WTI oil price of US\$48.75, heavy oil differential of US\$11.00 and a US\$ to Cdn\$ exchange rate of \$0.80. Year-end 2017 debt levels are anticipated to be between \$140 and \$145 million, up from our previous guidance of \$130 and \$135 million. The increase in year-end debt levels reflects an increase in capital spending and lower forecasted adjusted funds flow for the remainder of the year.

We anticipate oil and gas production to average between 10,000 and 11,000 boe/d in 2017, unchanged from our previous guidance. Production from the Onion Lake thermal facility was temporarily impacted by a planned facility turnaround and inspection which began in late June. Production is expected to return to full rates in August or early September. As a result of the turnaround, corporate production for Q3 2017 is expected to be between 9,000 and 9,500 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 "anticipate", "anticipated", "approximately", "believe", "plan", "planning", "planned", "project", "projects", "potential", "could", "estimate", "estimates", "estimated", "forecast", "forecasted", "likely", "expect", "expected", "may", "target", "impact", "new", "will", "should", "scheduled", "outlook" or similar words suggesting future outcomes.

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

- Total estimated capital costs, expected completion date and peak production date for the second phase of the Onion Lake thermal project as discussed in the Overview and 2017 Significant Events section;
- Proceeds from the issue of the senior secured notes and our existing senior credit facilities will be used to fund the construction of the second phase of our Onion Lake thermal project and for general corporate purposes as discussed in the 2017 Significant Events section;
- Improved Canadian dollar relative to the US dollar which will negatively impact our future revenues and cash flows as discussed in the Commodity Prices section;
- The estimated change in annualized adjusted funds flow for 2017 due to changes in key variables as discussed in the Commodity Prices section;
- Expectation that Onion Lake thermal production will return to full rates in August or early September after a three week turnaround as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas Sales section;
- Expected stock-based compensation expense for the remainder of 2017, 2018, 2019 and 2020 as discussed in the Stock-based Compensation section;
- The expected interest rate charged on our senior credit facilities for the remainder of 2017 as discussed in the Finance Costs section;
- Expectation that gross interest and financing charges are expected to increase during the remainder of 2017 as a result of the Company's recent issuance of senior secured second lien notes as discussed in the Finance Costs section;

- Potential future asset impairments or reversals of impairments as discussed in the Impairment section;
- Expected cash taxes to be paid during the remainder of 2017 as discussed in the Income Taxes section;
- 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.