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BLACKPEARL ANNOUNCES FOURTH QUARTER AND FULL YEAR 2016 FINANCIAL AND OPERATING RESULTS AND YEAR-END RESERVES AND RESOURCES, WORK COMMENCES ON PHASE 2 THERMAL EXPANSION AT ONION LAKE

CALGARY, ALBERTA – BlackPearl Resources Inc. ("we", "our", "us", "BlackPearl" or the "Company") (TSX: PXX) (NASDAQ Stockholm: PXXS) is pleased to announce its financial and operating results for the three and twelve months ended December 31, 2016, the results of its 2016 year-end oil and gas reserves and resource evaluations and the commencement of construction of the Phase 2 thermal expansion at Onion Lake.

Highlights and accomplishments included:

- Onion Lake is the cornerstone of the Company's current oil production. The first phase of thermal development reached and exceeded its design capacity of 6,000 barrels of oil per day (bbl/d) during the year with operating costs under $10/bbl. During Q4 2016, production from the project averaged 6,119 bbl/d. Our Board has sanctioned development of the 6,000 bbl/d Phase 2 expansion of the project and we have commenced construction. In addition, we have entered into a fixed price agreement to fabricate the central processing facilities and pad facilities for Phase 2. Total estimated capital costs for the project are between $180 and $185 million and the project is expected to be completed in mid-2018.

- During 2016, oil and gas production averaged 10,077 boe/day; a 21% increase compared to 2015 and higher than full year guidance for the year. The increase reflects the ramp-up of production from the Onion Lake thermal project during the year. Q4 2016 oil and gas production averaged 10,479 boe/day.

- During the year debt was reduced from $88 million to nil; the Company used its cash flow and proceeds from the sale of a royalty interest on our Onion Lake property to eliminate debt by year-end.

- At Blackrod, in 2016, we received regulatory approval for an 80,000 bbl/d SAGD development and the results from our successful pilot continue to support the commerciality of this large resource. In 2016, the pilot produced an average of 556 bbl/d, and cumulatively, has produced in excess of 460,000 barrels of oil.

- At Mooney, we were relatively quiet in 2016 as we shut-in a majority of the ASP flood due to low oil prices. However, as a result of the recent improvement in oil prices we re-initiated phase1 of the ASP flood. It will likely take six to twelve months before we see the full impact on production volumes from the re-start.

- During the fourth quarter of 2016, the Company sold a gross overriding royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay approximately 1.75% royalty on production from substantially all of its Onion Lake lands.

- Operating costs, on a per barrel of oil basis, dropped 38% in 2016 from 2015, which reflects the success of the Onion Lake thermal project as well as cost cutting measures implemented in our other producing areas.

- Q4 2016 revenue was $35 million and funds flow from operations (a non-GAAP measure) was $16 million, up from Q4 2015 as a result of higher oil prices. For the year, oil and gas revenue was $109 million and funds flow from operations was $45 million.

- Capital expenditures were $11 million in 2016 compared to $69 million in 2015. Reduced capital spending reflects lower oil prices and our desire to maintain a strong balance sheet.

- Proven plus probable reserves increased 6% in 2016 to 312 million barrels. The increase represents a 377% replacement of 2016 production. The increase is predominantly due to technical revisions and extensions in our Onion Lake area assets.

- Risked contingent resources (best estimate) for our three core properties totaled 499 million barrels of oil equivalent, comparable to 2015 resource estimates.

John Festival, President of BlackPearl, commented that "The past two years have been very difficult due to low oil prices; however, we did more than just shut in production, cut costs and survive. We have managed the construction and start-up of a best in class thermal project at Onion Lake which has paved the way for additional phases. We have also been able to enter 2017 with no debt and the financial capacity to fund phase 2 of our Onion Lake thermal project. Building a successful thermal project was the result of learning from our pilots, careful project management and teaming up with experienced vendors. Surviving difficult financial circumstances was the result of discipline both in our hedging program and in our capital allocation. We intend to employ both these characteristics as prices improve as we continue to grow and build in our core areas. In 2017, we will allocate capital to drilling primary wells and bringing on shut in production, but most importantly, our focus will be on our 6,000 barrel per day phase 2 expansion at Onion Lake. We have signed a contract to build the facilities for phase 2 and expect to announce the remaining debt instruments shortly that are necessary to fully fund our capital program. We anticipate funding the remainder of the project with no additional equity dilution to shareholders. Long life, low decline production will be the bedrock of our company as we look to the future, which will include the funding and construction of our Blackrod oil sands project. In addition, 2016 was a significant milestone for Blackrod as we received regulatory and environmental approval for an 80,000 bbl/d commercial development."

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2016	2015	2016	2015
Daily sales volumes				
Oil (bbls/d)	9,853	8,785	9,391	7,434
Bitumen (bbls/d) (1)	523	562	556	541
Combined (bbls/d)	10,376	9,347	9,947	7,975
Natural gas (mcf/d)	620	1,047	781	2,130
Combined (boe/d) (2)	10,479	9,521	10,077	8,330
Product pricing ($)				
Crude oil - per bbl	38,.83	27.65	31.57	35.00
Natural gas - per mcf	2.90	2.91	1.95	2.72
Combined - per boe (2)	38.61	27.45	31.30	34.14
Realized gains on risk management contracts – per boe	0.63	12.54	3.10	13.20
($000s, except where noted)				
Oil and natural gas revenue – gross	35,360	22,630	109,066	96,271
Net income (loss) for the period	(2,217)	(31,172)	(19,928)	(46,793)
Per share, basic ($)	(0.01)	(0.09)	(0.06)	(0.14)
Per share, diluted ($)	(0.01)	(0.09)	(0.06)	(0.14)
Cash flow from operating activities (3)	15,079	12,179	42,491	62,344
Funds flow from operations (4)	15,798	10,898	44,775	48,962

Capital expenditures	6,150	1,665	10,925	68,508
Working capital deficiency (surplus), end of period	4,995	(11,063)	4,995	(11,063)
Long term debt	-	88,000	-	88,000
Net Debt (5)	4,995	76,937	4,995	76,937
Shares outstanding, end of period (000s)	335,949	335,638	335,949	335,638

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

(2) Boe is based on a conversion ratio of 6 mcf of natural gas to 1 bbl 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 equivalency conversion method primarily applicable at the burner tip and is not intended to represent a value equivalency at the wellhead.

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

(4) Funds flow from operations is a non-GAAP measure (as defined herein) 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 standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Management utilizes funds flow from operations as a key measure to assess operating performance and the ability of the Company to finance operating activities, capital expenditures and debt repayments. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP.

(5) 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.

FOURTH QUARTER 2016 ACTIVITIES

Oil and natural gas sales increased 56% in the fourth quarter of 2016 to $35.4 million from $22.6 million in the same period in 2015. The increase in oil and gas sales is attributable to a 41% increase in average sales price received in the fourth quarter of 2016 and a 10% increase in production volumes (on a boe basis). WTI oil prices averaged US$49.29 per barrel in Q4 2016 compared to US$42.18 per barrel in Q4 2015. Higher WTI oil prices combined with comparable heavy oil differentials and a weaker Canadian dollar relative to the US dollar resulted in our wellhead price averaging $38.83 per barrel in the fourth quarter of 2016 compared with $27.65 per barrel in the fourth quarter of 2015.

BlackPearl sold an average of 10,479 boe/day during the fourth quarter of 2016 compared with 9,521 boe/day during the fourth quarter of 2015. Higher production in the fourth quarter of 2016 primarily reflects an increase in production from our Onion Lake thermal project. During the fourth quarter the thermal project produced 6,119 barrels of oil per day.

Production costs were $11.1 million or $12.11 per boe in the fourth quarter of 2016 compared to $14.7 million or $17.77 per boe in the fourth quarter of 2015. The decrease in per unit operating costs is mainly attributable to lower costs related to our Onion Lake thermal project. General and administrative expenses were $1.6 million in the fourth quarter of 2016 compared to $1.8 million in the fourth quarter of 2015.

During the fourth quarter, the Company sold a gross overriding royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay an approximate 1.75% royalty on production from substantially all of its Onion Lake lands.

During the year debt was reduced from $88 million to nil at the end of 2016. The Company used a significant portion of its cash flow and the proceeds from the royalty sale to reduce its debt in 2016.

Funds flow from operations in the fourth quarter of 2016 was $15.8 million compared to $10.9 million in the fourth quarter of 2015. The increase reflects higher revenues in Q4 2016, partially offset by lower realized gains on risk management contracts. Net loss in the fourth quarter of 2016 was $2.2 million compared to a net loss of $31.2 million in the fourth quarter of 2015. The decrease in net loss in Q4 2016 is primarily a result of no impairment losses recognized during 2016 compared to an impairment charge of $33 million recorded in 2015.

Capital spending was $6.2 million during the quarter compared with $1.7 million in Q4 2015.

Production

BlackPearl's Q4 2016 oil and gas sales volumes were 10,479 boe per day, a 10% increase over production during the same period in 2015. The increase in fourth quarter production is attributable to the Onion Lake thermal project.

	Three months ended December 31,		Twelve months ended December 31,	
Production by Area (boe/d)	2016	2015	2016	2015
Onion Lake – thermal	6,119	3,010	5,520	951
Onion Lake – conventional	2,011	2,914	2,135	3,312
Mooney	785	1,902	801	2,367
John Lake	837	955	863	989
Blackrod SAGD Pilot	523	562	556	541
Other	204	178	202	170
Total production	10,479	9,521	10,077	8,330

Operating Netback

	Three months ended December 31,		Twelve months ended December 31,	
($/boe)	2016	2015	2016	2015
Oil and natural gas revenue	38.61	27.45	31.30	34.14
Realized gains on risk management contracts	0.63	12.54	3.10	13.20
	39.24	39.99	34.40	47.34
Royalties	4.93	4.38	3.96	5.74
Transportation costs	2.69	1.23	2.24	1.13
Production costs	12.11	17.77	12.44	19.94
Operating netback[(1)]	19.51	16.61	15.76	20.53

(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.

Hedging Position

Periodically we will enter into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects. The table below summarizes the Company's current risk management contracts:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
2017					
Oil	500 bbls/d	January 1 to December 31	CDN$ WCS [(1)]	CDN$ 52.75/bbl	Swap
Oil	500 bbls/d	February 1 to December 31	CDN$ WCS [(1)]	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	February 1 to December 31	US$ WCS [(1)]	US$ 40.15/bbl	Swap
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS [(1)]	CDN$ 50.00/bbl	Swap
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS [(1)]	CDN$ 49.50/bbl	Swap
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS [(1)]	CDN$ 40.00/bbl to 52.50/bbl	Collar
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS [(1)]	CDN$ 40.00/bbl to 47.00/bbl	Collar
Oil	1,000 bbls/d	January 1 to December 31	US$ WTI [(2)]	US$ 60.00/bbl	Sold Call
2018					
Oil	500 bbls/d	January 1 to December 31	US$ WTI [(2)]	US$ 70.00/bbl	Sold Call

(1) WCS refers to Western Canadian Select, a heavy oil reference price in Alberta
(2) WTI refers to West Texas Intermediate, a light oil reference price in Cushing Oklahoma

2017 Outlook – Initial Guidance

Capital spending in 2017 will be approximately $200 million, with expansion of the Onion Lake thermal project our main focus. We have begun preliminary spending on planning and long lead items for the project with a target completion date of mid-2018. In addition to the expansion of the Onion Lake thermal project, we also plan to resume drilling on some of our conventional heavy oil projects at John Lake, Onion Lake and other minor project areas, as well as continuing to operate the Blackrod SAGD pilot.

We are planning to fund a significant portion of the capital costs of the Onion Lake expansion with our funds flow from operations, which we are budgeting to be between $65 and $70 million in 2017, and our undrawn credit facilities. We are looking to supplement these sources with $75 to $100 million of additional term debt financing to provide us with financial flexibility during the construction phase. In the event that we are unable to obtain additional financing we will reduce capital spending on our conventional heavy oil projects. Year-end debt is expected to be between $135 and $140 million.

Oil and gas production is expected to average between 10,000 and 11,000 boe/d in 2017. This will include bringing back some of our shut-in production at Onion Lake as well as reactivating phase one of the ASP flood at Mooney.

The initial guidance is based on a WTI oil price of US$54.50/bbl, a heavy oil differential of US$14.75/bbl and a Cdn/US dollar exchange rate of 0.75.

Oil and Gas Reserves

The following tables summarize certain information contained in the independent reserves report prepared by Sproule Unconventional Limited ("Sproule") as of December 31, 2016. The report was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserve information as required under NI 51-101 has been included in the Company's Annual Information Form which has been filed on SEDAR. It should not be assumed that the net present value of reserves estimated by Sproule represents the fair market value of these reserves.

Summary of Oil and Gas Reserves

(Company interest, before royalties)	Heavy Crude Oil	Bitumen	Natural Gas	2016 Total	2015 Total
	(Mbbl)	(Mbbl)	(MMcf)	(MBoe)	(MBoe)
Proved developed producing	18,461	628	216	19,125	19,907
Proved developed non-producing	3,400	0	169	3,428	2,673
Proved undeveloped	53,399	429	71	53,840	41,376
Total proved	75,260	1,057	456	76,393	63,956
Probable	56,374	178,742	421	235,186	230,010
Total proved plus probable	131,634	179,799	877	311,579	293,966

Notes:

(1) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, 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) Columns may not add due to rounding.

Net Present Value of Reserves

($000s)	0%	5%	10%	15%	20%
Before Tax					
Proved					
Developed producing	459,650	409,646	364,468	326,303	294,658
Developed non-producing	57,041	44,809	35,721	28,902	23,723
Undeveloped	1,436,295	660,090	335,306	184,234	106,443
Total proved	1,952,986	1,114,545	735,495	539,439	424,824
Probable	6,101,866	2,705,896	1,319,121	681,908	358,751
Total proved plus probable	8,054,852	3,820,441	2,054,616	1,221,347	783,575
After Tax					
Proved					
Developed producing	459,650	409,646	364,468	326,303	294,658
Developed non-producing	57,041	44,809	35,721	28,902	23,723
Undeveloped	1,064,317	492,031	250,036	136,658	77,834
Total proved	1,581,008	946,486	650,225	491,863	396,215
Probable	4,418,620	1,928,767	910,614	445,040	210,965
Total proved plus probable	5,999,628	2,875,253	1,560,839	936,903	607,180

Notes:
(1) Based on Sproule's December 31, 2016 forecast prices.
(2) Columns may not add due to rounding.

Estimated Future Development Capital

The following table summarizes the future development capital ("FDC") Sproule estimates is required to bring total proved and total proved plus probable reserves on production.

($ Millions)	Total Proved	Total Proved + Probable
2017	47.6	183.9
2018	25.4	91.1
2019	26.3	50.4
2020	11.5	86.6
2021	55.8	357.2
Remainder	465.5	1,927.0
Total FDC undiscounted	632.1	2,696.2
Total FDC discounted at 10%	246.0	1,160.1

Reconciliation of Changes in Reserves

The following table summarizes the changes in Sproule's evaluation of the Company's share of oil and natural gas reserves (before royalties) from December 31, 2015 to December 31, 2016.

	Heavy Crude Oil	Bitumen	Natural Gas	BOE
	(Mbbl)	(Mbbl)	(MMcf)	(MBOE)
Proved				
Balance, Dec 31, 2015	63,446	429	487	63,956
Extensions and improved recovery	9,388	0	0	9,388
Technical revisions	6,144	930	322	7,128
Economic factors	(281)	(98)	(67)	(390)
Production	(3,437)	(204)	(286)	(3,689)
Balance, Dec 31, 2016	75,260	1,057	456	76,393

Probable				
Balance, Dec 31, 2015	50,612	179,338	363	230,010
Extensions and improved recovery	6,901	0	0	6,901
Technical revisions	(1,177)	(299)	35	(1,470)
Economic factors	38	(297)	23	(255)
Production	0	0	0	0
Balance, Dec 31, 2016	56,374	178,742	421	235,187
Proved plus Probable				
Balance, Dec 31, 2015	114,058	179,767	850	293,966
Extensions and improved recovery	16,289	0	0	16,289
Technical revisions	4,967	631	357	5,658
Economic factors	(243)	(395)	(44)	(645)
Production	(3,437)	(204)	(286)	(3,689)
Balance, Dec 31, 2016	131,634	179,799	877	311,579

Note:
(1) Columns may not add due to rounding

The pricing assumptions used in the Sproule evaluation are summarized below.

Pricing Assumptions

Year	WTI Cushing 40° API	Canadian Light Sweet Crude 40° API	Western Canadian Select 20.5° API	Alberta AECO-C Spot	Inflation rate	Exchange rate
	(US$/bbl)	(CDN$/bbl)	(CDN$/bbl)	(CDN$/MMBtu)	(%/yr)	(US$/Cdn$)
2017	55.00	65.58	53.12	3.44	0.0	0.78
2018	65.00	74.51	61.85	3.27	2.0	0.82
2019	70.00	78.24	64.94	3.22	2.0	0.85
2020	71.40	80.64	66.93	3.91	2.0	0.85
2021	72.83	82.25	68.27	4.00	2.0	0.85
2022	74.28	83.90	69.64	4.10	2.0	0.85
2023	75.77	85.58	71.03	4.19	2.0	0.85
2024	77.29	87.29	72.45	4.29	2.0	0.85
2025	78.83	89.03	73.90	4.40	2.0	0.85
2026	80.41	90.81	75.38	4.50	2.0	0.85
2027	82.02	92.63	76.88	4.61	2.0	0.85
			Escalation rate of 2.0% thereafter			

Notes:
(1) The pricing assumptions were provided by Sproule.
(2) None of the Company's future production is subject to a fixed or contractually committed price.

Definitions:
(a) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(b) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
(c) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.
(d) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
(e) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
(f) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure

(for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(g) The Net Present Value (NPV) is based on Sproule forecast pricing and costs. The estimated NPV does not necessarily represent the fair market value of our reserves. There is no assurance that forecast prices and costs assumed in the Sproule evaluations will be attained, and variances could be material.

Contingent Resources

The following tables summarize certain information contained in the contingent resource evaluations prepared by Sproule as of December 31, 2016. The reports were independently prepared in accordance with definitions, standards and procedures contained in the COGE Handbook.

It should not be assumed that the estimates of recovery, production, and net revenue presented in the tables below represent the fair market value of the Company's contingent resources. There are certain contingencies which currently prevent the classification of these contingent resources as reserves. Information on these contingencies is provided in the footnotes to the tables below. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Please refer to our Annual Information Form for a more detailed discussion of our contingent resources.

An estimate of risked net present value of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Best Estimate (P50) Contingent Resource Volumes – By Property [(1)(2)]

			Risked Volumes[(4)]				Unrisked Volumes			
			Heavy Crude Oil		Bitumen		Heavy Crude Oil		Bitumen	
Project	Maturity Subclass [(3)]	Chance of Development[(4)]	Gross[(5)]	Net	Gross[(5)]	Net	Gross[(5)]	Net	Gross[(5)]	Net
			(Mbbl)		(Mbbl)		(Mbbl)		(Mbbl)	
Blackrod [(6)]	Development/ pending	80%	0	0	452,908	370,479	0	0	566,135	463,099
Onion Lake [(7)]	Development/ pending	90%	35,101	27,807	0	0	39,001	30,897	0	0
Mooney [(8)]	Development/ on hold	71%	11,154	9,731	0	0	15,709	13,705	0	0

NPV of Best Estimate (P50) Contingent Resource Volumes – By Property

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Project	($M)				
Risked Volumes [(4)]					
Blackrod	9,494,445	2,825,717	851,304	212,292	-4,585
Onion Lake	1,118,061	411,066	171,668	79,826	40,034
Mooney	335,947	160,233	79,854	40,897	21,121
Unrisked Volumes					
Blackrod	11,868,057	3,532,146	1,064,131	265,366	-5,731
Onion Lake	1,242,290	456,740	190,742	88,695	44,482
Mooney	473,165	225,681	112,471	57,602	29,749

Project	Net Present Values of Future Net Revenue After Income Taxes (10) Discounted at (%/year) 0%	5%	10%	15%	20%
	($M)				
Risked Volumes (4)					
Blackrod	6,817,151	1,943,718	514,839	67,498	-73,076
Onion Lake	806,412	291,145	117,894	52,154	24,118
Mooney	244,534	114,986	55,964	27,593	13,372
Unrisked Volumes					
Blackrod	8,521,438	2,429,647	643,549	84,373	-91,345
Onion Lake	896,013	323,495	130,993	57,949	26,798
Mooney	344,414	161,953	78,823	38,863	18,834

Notes:

(1) Contingent Resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

(2) There are three classifications of contingent resources: Low Estimate, Best Estimate and High Estimate. Best estimate (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

(3) Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Company's contingent resources are classified as either development pending or development on hold:

(a) Development pending is where resolution of the final conditions of development are being actively pursued, indicating there is a high chance of development.

(b) Development on hold is where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

(4) Chance of Development is defined as the probability of a project being commercially viable. Sproule's estimate of unrisked contingent resources have been adjusted for risk based on the chance of development (risked amounts represent unrisked values multiplied by the Chance of Development).

(5) "Gross" means the Company's working interest share in the contingent resources of bitumen and heavy oil before deducting royalties. The Company has a 100% working interest at Blackrod and Mooney, and a 50 to 100% working interest at Onion Lake.

(6) The established recovery technology to be used in phases 3 and 4 of the Blackrod project is the SAGD process, the same process that is being used in the successful pilot that is currently being conducted within the Blackrod reservoir. The contingencies in the Sproule Report associated with the Company's Blackrod contingent resources are due to the following: (a) the requirement for more evaluation drilling, as required by the regulatory process, to define the reservoir characteristics to assist in the implementation and operation of the SAGD process; (b) the absence of submission of an application to expand the commercial SAGD development beyond the phase 2 project area; (c) the absence of corporate commitment related to the final investment decision and endorsement from the Board of Directors of the Company to move forward with commercial development of Phases 3 and 4 of the Blackrod project; and (d) the uncertainty of timing of production and development of Phases 3 and 4 of the Blackrod project. For the Blackrod project contingent resources, the estimated timing of first commercial production is 2025 and the estimated capital to reach first commercial production is $0.97 billion (unrisked and unescalated for inflation).

(7) The recovery of the Company's Onion Lake contingent resources will use a combination of production processes: the established modified SAGD process for phase 3 of the Onion Lake thermal project, the same process that is already utilized commercially in phase 1 of the Onion Lake thermal project; and the established cold heavy oil production with sand (CHOPS) process to extend the primary development area, the same CHOPS process that has already been extensively deployed throughout the field.

- For phase 3 of the Onion Lake thermal project, the contingencies in the Sproule Report associated with the Company's Onion Lake contingent resources are due to the following: (a) the requirement for more evaluation drilling to define the reservoir characteristics to assist in the implementation and operation of the modified SAGD recovery process; and (b) the absence of an agreement between the Company and OLCN/OLE for thermal EOR development in the lands currently leased by the Company but outside the thermal EOR development area, the thermal EOR volumes assigned to these lands were classified as contingent resources. In addition, an application to expand the commercial modified SAGD development beyond the existing OLCN/OLE approved thermal EOR development area and facility capacities has not been submitted by the Company. It is expected that as the Company nears a final development decision for developing additional acreage, OLCN/OLE agreements will be affirmed and further expansion applications will be submitted, at which point this contingency would be lifted. For the Onion Lake thermal project contingent resources, the estimated timing of first commercial production is 2022, while the estimated capital to reach first commercial production is $48.4 million (unrisked and unescalated for inflation).

- For the extension of the primary development area, the contingencies in the Sproule Report associated with the Company's Onion Lake contingent resources are due to the following: (a) the requirement for more evaluation drilling to confirm the geological continuity of the reservoir and reduce the distance from proven productivity; and (b) the potential for the current agreements with the Onion Lake Cree Nation (OLCN), which are subject to policies and approvals by Indian Oil and Gas Canada (IOGC), required to be renegotiated due to changes imposed by IOGC. First commercial production for the primary development area has already been achieved and, as a result, estimated capital to reach first commercial production is nil.

(8) The established recovery technology to be used for phases 3 and 4 of the Mooney project is the established ASP flood process, the same process that is already deployed commercially in phase 1 of the Mooney field. The contingencies in the Sproule Report associated with the Company's Mooney contingent resources are due to the following: (a) the requirement for more evaluation wells to confirm the reservoir characteristics needed for the ASP process; (b) the absence of regulatory approvals to expand the ASP development area beyond the phase 1 and phase 2 project areas; (c) the absence of a final investment decision from the Board of Directors of the Company to move forward with the ASP flood expansion to phases 3 and 4 of the Mooney project and (d) the uncertainty of timing of production and development of phases 3 and 4 of the Mooney project. First commercial production for the Mooney ASP flood has already been achieved and, as a result, estimated capital to reach first commercial production at the Mooney ASP flood is nil.

(9) The amounts included in these tables do not include the volume or net present value of the Company's proved plus probable reserves previously assigned by Sproule to these properties.

(10) The after-tax net present value of the Company's contingent resources reflects the tax burden on the properties on a stand-alone basis. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion & analysis of the Company should be consulted for information at the level of the business entity.

Other

The Company's financial statements, notes to the financial statements, management's discussion and analysis and Annual Information Form have been filed on SEDAR (www.sedar.com) and are available on the Company's website (www.blackpearlresources.ca). The Annual Information Form includes the Company's reserves and resource data for the period ended December 31, 2016 as evaluated by Sproule and other oil and natural gas information prepared in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. BlackPearl's annual meeting of shareholders will be held on May 4, 2017 in Calgary Alberta.

Forward-Looking Statements

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

In particular, this release contains forward-looking statements pertaining to the estimated capital costs of between $180 to $185 million to construct phase 2 of the Onion Lake thermal project and the estimated mid-2018 completion date, estimated timing to see the full impact on production of the re-initiation of the ASP flood at Mooney, anticipated debt funding for the Phase 2 thermal expansion at Onion Lake with no additional equity dilution to fund the expansion, estimated volumes and net present values of BlackPearl's proved and probable reserves and contingent resources and all the information under *2017 Outlook – Initial Guidance*.

The forward-looking information is based on, among other things, expectations and assumptions by management regarding its future growth, future production levels, future oil and natural gas prices, continuation of existing tax, royalty and regulatory regimes, foreign exchange rates, estimates of future operating costs, timing and amount of capital expenditures, performance of existing and future wells, recoverability of the Company's reserves and contingent resources, the ability to obtain financing on acceptable terms, availability of skilled labour and drilling and related equipment on a timely and cost efficient basis, general economic and financial market conditions, environment matters and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

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

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

Non-GAAP Measures

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

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

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	2016	2015	2016	2015
Cash flow from operating activities	15,079	12,179	42,491	62,344
Add (deduct):				
Decommissioning costs incurred	26	152	580	531
Changes in non-cash working capital related to operations	693	(1,433)	1,704	(13,913)
Funds flow from operations	15,798	10,898	44,775	48,962

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

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

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The information in this release is subject to the disclosure requirements of the Company under the EU Market Abuse Regulation and the Swedish Securities Markets Act. The information was publicly communicated on February 23, 2017 at 3:00 p.m. Mountain Time.

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 year ended December 31, 2016. These results are being compared with the year ended December 31, 2015. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2016, together with the accompanying notes.

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

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

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

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

Non-GAAP Financial Measures

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

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

	Three months ended December 31		Year Ended December 31	
($000s)	**2016**	2015	**2016**	2015
Cash flow from operating activities [1]	**15,079**	12,179	**42,491**	62,344
Add (deduct):				
Decommissioning costs incurred	**26**	152	**580**	531
Changes in non-cash working capital related to operations	**693**	(1,433)	**1,704**	(13,913)
Funds flow from operations [2]	**15,798**	10,898	**44,775**	48,962

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

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

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

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

($000s)	**December 31, 2016**	December 31, 2015
Long-term debt [1]	–	88,000
Add (deduct) working capital:		
Cash and cash equivalents	**(5,368)**	(2,300)
Trade and other receivables	**(13,391)**	(10,801)
Inventory	**(46)**	(605)
Prepaid expenses and deposits	**(705)**	(1,283)
Fair value of risk management assets	–	(10,548)
Accounts payable and accrued liabilities	**17,950**	13,939
Current portion of decommissioning liabilities	**644**	535
Current portion of deferred consideration	**404**	–
Fair value of risk management liabilities	**5,507**	–
Net debt [2]	**4,995**	76,937

(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 share-holders 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 February 22, 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 with the first phase constructed and put on production in 2015;
- Mooney, Alberta – a conventional heavy oil property currently developed using both horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property, in the exploration and evaluation phase, located in the Athabasca oil sands region of which the Company is currently operating a pilot project using the SAGD recovery process.

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

2016 SIGNIFICANT EVENTS

- During the fourth quarter of 2016, the Company sold a gross overriding royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay approximately 1.75% royalty on production from substantially all of its Onion Lake lands. The proceeds of the sale were used to re-pay bank indebtedness, which will free up borrowing capacity on our credit facilities that is expected to be used to partially fund the expansion of our thermal operations at Onion Lake in addition to continued development of our other core projects.
- In 2016, the Company received regulatory and environmental approval from the Alberta Energy Regulator and Alberta government for its 80,000 bbls/d Blackrod SAGD commercial development application.
- During 2016, oil and gas production averaged 10,077 boe/d; a 21% increase compared to 2015. The increase was mainly attributable to the first phase of the Onion Lake thermal project which has been on production for over a year. During 2016, production from this project averaged 5,520 bbls/d, with a steam to oil ratio of 2.78 and during the fourth quarter production from the Onion Lake thermal project averaged 6,119 bbls/d.
- Crude oil prices were lower in 2016, with WTI oil prices averaging US$43.32 per bbl compared to US$48.80 per bbl during 2015. The decline in crude oil prices was partially offset by realized gains on crude oil hedging contracts. For the year ended December 31, 2016, the Company realized gains of $10.8 million from these contracts.
- Due to low oil prices, the Company limited capital spending in 2016 and used the majority of its cash flow from operating activities to reduce debt. Capital expenditures during the year were $10.9 million, with approximately $8.2 million spent at the Onion Lake thermal project related to facility improvements and planning costs for the second phase of the project, $1.1 million spent at Onion Lake related to the drilling of three gross conventional heavy oil wells and $1.6 million spent in other areas.
- Oil and gas sales during 2016 were $109.1 million and funds flow from operations (a non-GAAP measure) were $44.8 million. For the year ended December 31, 2016, the Company incurred a net loss of $19.9 million.

- As a result of the Company's cost reduction initiative, operating and transportation costs averaged $14.68/bbl in 2016, a 30% decrease from 2015.
- During 2016, 310,669 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 2016.
- During the fourth quarter of 2016 the Company's lending syndicate completed their semi-annual review of our credit facilities and agreed to maintain the borrowing amount available to the Company. At December 31, 2016, BlackPearl had a working capital deficiency of $5.0 million and no bank debt, leaving $117.5 million available to be drawn under the Company's existing credit facilities. During 2016, the Company repaid the entire outstanding bank debt balance of $88 million which was owed at the beginning of the year.
- BlackPearl proved plus probable oil and gas reserves were 312 million boe, before royalties, as at December 31, 2016. This amount was determined by BlackPearl's independent reserve evaluators, Sproule Unconventional Limited ("Sproule"). The estimated pre-tax net present value of the future net cash flows of the proved plus probable reserves, discounted at 10% per annum was $2.1 billion ($6.12 per common share).
- Sproule also attributed, on a risked basis, contingent resources (best estimate) of 499 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 34). The estimated pre-tax net present value of the risk adjusted future net cash flows of contingent resources (best estimate), discounted at 10% per annum was $1.1 billion.

ANNUAL FINANCIAL INFORMATION

($000s, except where noted)	**2016**	2015	2014
Production (boe/d) (1)	**10,077**	8,330	9,287
Oil and gas sales	**109,066**	96,271	228,345
Realized gain on risk management contracts	**10,793**	37,227	1,870
Unrealized gain (loss) on risk management contracts	**(15,283)**	(11,303)	20,628
Net income (loss)	**(19,928)**	(46,793)	26,825
Per share – basic and diluted ($)	**(0.06)**	(0.14)	0.08
Cash flow from operating activities	**42,491**	62,344	78,388
Funds flow from operations (2)	**44,775**	48,962	89,723
Long-term debt	**–**	88,000	29,000
Capital expenditures	**10,925**	68,508	235,366
Total assets at year end	**732,404**	808,344	837,773
Common shares outstanding (000s)	**335,949**	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. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

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

SELECTED QUARTERLY INFORMATION

	2016				2015			
($000s, except where noted)	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (boe/d) (1)	10,479	10,951	9,698	9,166	9,521	7,478	8,051	8,269
Oil and gas sales	35,360	32,367	28,318	13,021	22,630	20,814	30,712	22,115
Oil sales ($/bbl)	38.83	34.15	34.44	16.77	27.65	35.02	47.52	32.05
Gas sales ($/mcf)	2.90	2.10	1.29	1.77	2.91	2.88	2.61	2.63
Oil and gas sales ($/boe)	38.61	33.87	34.03	16.67	27.45	34.05	45.37	31.25
Production & transportation costs	13,550	13,603	12,246	11,736	15,666	12,843	14,245	16,686
Production costs ($/boe)	12.11	12.13	13.23	12.35	17.77	20.04	19.86	22.48
Transportation costs ($/boe)	2.69	2.11	1.48	2.68	1.23	0.97	1.18	1.10
Gain (loss) on risk management contracts								
Realized	578	2,137	1,958	6,120	10,334	7,940	5,245	13,708
Unrealized	(5,676)	(538)	(8,597)	(472)	1,778	11,826	(13,533)	(11,374)
Net income (loss)	(2,217)	556	(8,945)	(9,322)	(31,172)	5,402	(10,079)	(10,944)
Per share, basic and diluted ($)	(0.01)	0.00	(0.03)	(0.03)	(0.09)	0.01	(0.03)	(0.03)
Capital expenditures	6,150	1,753	945	2,077	1,665	7,870	15,992	42,981
Cash flow from operating activities	15,079	16,441	7,184	3,787	12,179	14,216	12,100	23,849
Funds flow from operations (2)	15,798	14,202	11,497	3,278	10,898	10,156	14,968	12,940
Long-term debt	–	67,000	80,000	86,000	88,000	97,000	94,000	78,000
Total assets (end of period)	732,404	773,206	782,591	795,336	808,344	861,107	864,926	866,018
Shares outstanding (000s)	335,949	335,647	335,647	335,638	335,638	335,638	335,638	335,638
Weighted average shares outstanding								
Basic	335,733	335,646	335,641	335,638	335,638	335,638	335,638	335,638
Diluted	340,686	337,959	335,641	335,638	335,638	335,638	335,638	335,638

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

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

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

BUSINESS ENVIRONMENT

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

Commodity Prices

	Year Ended December 31		2016				2015			
	2016	2015	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US$/bbl)	43.32	48.80	49.29	44.94	45.59	33.45	42.18	46.43	57.94	48.63
Western Canadian Select (WCS) (Cdn$/bbl)	38.89	44.80	46.62	41.02	41.61	26.31	36.86	43.27	56.95	42.11
Differential – WCS/WTI (US$/bbl)	13.90	13.77	14.34	13.51	13.30	14.32	14.57	13.39	11.62	14.71
Differential – WCS/WTI (%)	32.1%	28.2%	29.1%	30.1%	29.2%	42.8%	34.5%	28.8%	20.1%	30.2%
Average Natural Gas Prices										
AECO gas (Cdn$/GJ)	2.05	2.55	2.93	2.20	1.33	1.74	2.34	2.75	2.52	2.61
Average Foreign Exchange (US$ per Cdn$1)	0.757	0.782	0.750	0.766	0.776	0.727	0.749	0.764	0.813	0.806

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 were lower in 2016 compared to 2015. WTI oil prices averaged US$43.32 per bbl in 2016, 11% lower than the average of US$48.80 per bbl in 2015. The decrease in oil prices has been attributed to a global over-supply of oil, high oil inventory levels, a slowdown in demand due to weaker global economic conditions, a strong US dollar and geopolitical events in various oil producing areas.

During the fourth quarter of 2016, oil prices improved as WTI averaged US$49.29 per bbl compared to US$44.94 per bbl in the third quarter of 2016 and US$42.18 per bbl in the fourth quarter of 2015. The increase in fourth quarter crude oil pricing has been attributed to improving global demand for oil, lower production volumes and the decision by the Organization of Petroleum Exporting Countries (OPEC) and certain non-OPEC countries to reduce their oil output by approximately 1.8 million bbls/d.

The heavy oil differential (WTI oil prices compared to WCS oil prices) was relatively flat in 2016 averaging US$13.90 per bbl compared to US$13.77 per bbl in 2015; however, heavy oil differentials as a percentage of WTI prices widened to 32.1% in 2016 compared to 28.2% in 2015. In the fourth quarter of 2016, the heavy oil differential widened compared to third quarter of 2016 due to a decrease in seasonal demand and previous production disruptions, caused by forest fires, coming back online.

While reduced production levels as a result of the lower oil price environment has alleviated some of the short-term transportation issues, take-away capacity remains tight for oil producers in Canada. With increased oil production expected in Canada from new and expanded oil sands projects, securing additional pipeline capacity to tidewater is important to ensure Canadian producers receive world prices for their oil. During the fourth quarter of 2016, the federal government approved the expansion of the existing Trans Mountain Express Pipeline and the Enbridge Line 3 replacement project. The proposed expansion of the existing Trans Mountain Express Pipeline would expand capacity to carry up to 890,000 bbls/d of oil to ports in Vancouver, from the current capacity of approximately 300,000 bbls/d and the Line 3 replacement project would expand capacity to carry up to 760,000 bbls/d of oil to Wisconsin, from the current pressure restricted capacity of approximately 390,000 bbls/d. There is an additional pipeline proposal in Canada, the Energy East pipeline, which would transport increased oil production to Eastern Canada. However, this pipeline proposal has not received regulatory approval. Recently in the US, the newly inaugurated President approved the Keystone XL pipeline with conditions, reversing the previous administration's decision. The Keystone XL pipeline would transport increased oil production to the US Gulf Coast. In general, these proposed pipelines have garnered significant opposition against them from environmental and other groups and there is no assurance that any of these pipeline projects will get built.

Natural gas prices decreased in 2016 averaging $2.05/GJ compared to $2.55/GJ in 2015. The decrease in natural gas prices during 2016 is attributable to higher gas storage levels due to a relatively mild winter earlier in the year throughout much of North America which reduced the demand for natural gas for heating. 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. Natural gas prices increased in the fourth quarter of 2016 averaging $2.93/GJ compared to $2.20/GJ in the third quarter of 2016 due to cold weather during the period resulting in higher demand for heating. These higher natural gas prices in the fourth quarter of 2016 increased our operating 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 weakened against the US dollar in 2016, which partially mitigated the effect of lower crude oil prices on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.76 during 2016 compared to Cdn$1 = US$0.78 during 2015.

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 funds flow from operations for 2016 [(1) (2)]:

Key variable	Change ($)	$000s
West Texas Intermediate (WTI) (US$/bbl)	1.00	1,034
Realized crude oil price (Cdn$/bbl)	1.00	1,418
US $ to Canadian $ exchange rate	0.01	591

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

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

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

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Daily production/sales volumes				
Oil (bbls/d)	**9,853**	8,785	**9,391**	7,371
Bitumen – Blackrod (bbls/d) (2)	**523**	562	**556**	541
Oil – Onion Lake thermal (bbls/d) (3)	**–**	–	**–**	63
Combined (bbls/d)	**10,376**	9,347	**9,947**	7,975
Natural gas (Mcf/d)	**620**	1,047	**781**	2,130
Total production (boe/d) (1)	**10,479**	9,521	**10,077**	8,330
Product pricing (excluding risk management activities) (2) (3)				
Oil ($/bbl)	**38.83**	27.65	**31.57**	35.00
Natural gas ($/Mcf)	**2.90**	2.91	**1.95**	2.72
Combined ($/boe) (1)	**38.61**	27.45	**31.30**	34.14
Sales ($000s) (2) (3)				
Oil and gas sales – gross	**35,360**	22,630	**109,066**	96,271
Royalties	**(4,516)**	(3,612)	**(13,785)**	(16,190)
Oil and gas revenues – net	**30,844**	19,018	**95,281**	80,081

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

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

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

Oil and natural gas sales increased 13% in 2016 to $109.1 million from $96.3 million in 2015. The increase in oil and gas sales is attributable to a 21% increase in production volumes (on a boe basis) in 2016 compared to 2015, partially offset by an 8% decrease in average sale price received.

Lower WTI crude oil prices and wider heavy oil differentials partially offset by a weaker Canadian dollar relative to the US dollar contributed to a decrease in our realized crude oil sales prices in 2016. Our average oil wellhead sales price, prior to the impact of risk management activities, in 2016 was $31.57 per bbl compared with $35.00 per bbl in 2015.

Production growth in 2016 compared to 2015 came from the first phase of our Onion Lake thermal project. The project has been on production for over a year and in June production reached its design capacity of 6,000 bbls/d. During the fourth quarter of 2016, production from this project averaged 6,119 bbls/d and during 2016 averaged 5,520 bbls/d.

Production in our non-thermal areas declined in 2016, primarily due to natural declines combined with limited new drilling activity due to low oil prices. In addition, we have selectively shut-in some of our higher cost production that is not economic in the current oil price environment. At Onion Lake, we have approximately 750 bbls of oil per day currently shut-in. As well, during the first quarter of 2016, we elected to shut-in the majority of the phase one ASP flood at Mooney, or approximately 900 bbls of oil per day. With the recent improvement in crude oil prices, we plan to selectively bring back on production some of the shut-in wells at Mooney and Onion Lake.

Oil and natural gas sales increased 56% in the fourth quarter of 2016 to $35.4 million from $22.6 million in the same period in 2015. The increase in oil and gas sales is attributable to a 41% increase in average sales price received in the fourth quarter of 2016 and a 10% increase in production volumes (on a boe basis).

On a boe basis, 99% of the Company's oil and natural gas production in 2016 was heavy oil or bitumen. The Onion Lake area accounted for 76% of total production in 2016.

	Three months ended December 31		Year Ended December 31	
Production by area *(boe/d)*	**2016**	2015	**2016**	2015
Onion Lake – thermal	**6,119**	3,010	**5,520**	951
Onion Lake – conventional	**2,011**	2,914	**2,135**	3,312
Mooney	**785**	1,902	**801**	2,367
John Lake	**837**	955	**863**	989
Blackrod	**523**	562	**556**	541
Other	**204**	178	**202**	170
Total production	**10,479**	9,521	**10,077**	8,330

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 2016, the pilot well produced an average of 556 bbls/d of bitumen and the net revenues capitalized for 2016 were $0.1 million ($2.1 million loss in 2015).

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

Risk Management Activities

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

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the fair values of our outstanding risk management contracts. The Company had a net loss of $4.5 million on its risk management contracts during 2016, consisting of a $10.8 million realized gain on the contracts and an unrealized loss of $15.3 million. The realized gain on risk management contracts was the equivalent of adding $3.10 per bbl to our wellhead price during 2016.

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2016**	2015	**2016**	2015
Realized gain on risk management contracts	**578**	10,334	**10,793**	37,227
Per boe ($)	**0.63**	12.54	**3.10**	13.20
Unrealized gain (loss) on risk management contracts	**(5,676)**	1,778	**(15,283)**	(11,303)

The table below summarizes the Company's outstanding commodity contracts as at December 31, 2016:

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

At December 31, 2016, these contracts had a fair value of approximately $6.0 million liability. A 10% decrease to the oil price used to calculate the fair value of these contracts would result in an approximate $7.5 million increase in fair value.

The table below summarizes commodity contracts the Company entered into subsequent to December 31, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	February 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	February 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap

Royalties

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Royalties ($000s)	**4,516**	3,612	**13,785**	16,190
Per boe ($)	**4.93**	4.38	**3.96**	5.74
As a percentage of oil and gas sales	**13%**	16%	**13%**	17%

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

Royalties were $13.8 million in 2016, down from $16.2 million in 2015. The decrease in royalties paid reflects lower royalty rates in 2016. Royalties as a percentage of oil and gas sales decreased to 13% in 2016 from 17% in 2015. This decrease is attributable to an increase in production from the Onion Lake thermal project. Production from this project was 55% of our total production in 2016 (11% in 2015). During the pre-payout period the royalties from this project will be approximately 10%, which is lower than our average royalty rate for our other producing areas.

In late 2016, the Company sold a royalty interest on substantially all future production from its Onion Lake lands whereby the Company will pay approximately a 1.75% royalty and as a result, royalty rates in 2017 and future periods will increase to reflect this new royalty.

Transportation Costs

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Conventional Production				
Transportation costs ($000s)	**318**	379	**969**	2,555
Per boe ($)	**0.93**	0.69	**0.66**	1.00
Thermal Production				
Transportation costs ($000s)	**2,144**	639	**6,832**	639
Per boe ($)	**3.81**	2.31	**3.38**	2.31
Total Production				
Transportation costs ($000s)	**2,462**	1,018	**7,801**	3,194
Per boe ($)	**2.69**	1.23	**2.24**	1.13

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 2016 to $7.8 million from $3.2 million in 2015. This increase is attributable to increased production from our Onion Lake thermal project which ships mostly clean marketable crude oil.

Production Costs

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Conventional Production				
Production costs ($000s)	**6,387**	8,522	**24,696**	50,120
Per boe ($)	**18.59**	15.57	**16.87**	19.71
Thermal Production				
Production costs ($000s)	**4,701**	6,126	**18,638**	6,126
Per boe ($)	**8.35**	22.12	**9.22**	22.12
Total Production				
Production costs ($000s)	**11,088**	14,648	**43,334**	56,246
Per boe ($)	**12.11**	17.77	**12.44**	19.94

Total production costs decreased 23% in 2016 to $43.3 million from $56.2 million in 2015. On a per boe basis, total production costs decreased 38% in 2016 to $12.44 per boe from $19.94 per boe in 2015. The decrease in total production costs was made up of a drop in costs related to our conventional production offset by production costs from our new thermal project at Onion Lake.

The decrease in conventional production costs in 2016 is attributable, in part, to a 38% decrease in conventional production volumes. In addition, due to low oil prices the Company has been focusing on reducing production costs. This included negotiating lower service rates with various suppliers and contractors, deferring well servicing work and shutting-in specific wells in the Onion Lake area that are not economic at current oil prices. The Company also temporarily shut-in the majority of the production from wells in the first phase of the Mooney ASP flood in early 2016 due to the continued low crude oil prices, which also contributed to the decrease in conventional production costs. The increase in thermal production costs in 2016 reflects the steady ramp-up in production from our Onion Lake thermal project, which commenced commercial production in October 2015. Purchasing natural gas to make steam is our largest single expense on this project and therefore production costs can fluctuate based on the price of natural gas. To date, we have not entered into any contracts to fix the price of natural gas we purchase.

The decrease in thermal production costs in the fourth quarter of 2016 compared to the same period in 2015 is primarily attributable to the first phase of the Onion Lake thermal project being in the ramp-up phase in the fourth quarter of 2015 whereas in 2016 the project reached design capacity and achieved operating efficiencies.

Operating Netback [(1) (2)]

	Year Ended December 31			
	2016	2016	2015	2015
	$000s	$/boe	$000s	$/boe
Oil and gas sales	109,066	31.30	96,271	34.14
Royalties	13,785	3.96	16,190	5.74
Transportation costs	7,801	2.24	3,194	1.13
Production costs	43,334	12.44	56,246	19.94
Operating netback before realized risk management contracts	44,146	12.66	20,641	7.33
Realized gain on risk management contracts	10,793	3.10	37,227	13.20
Operating netback after realized risk management contracts	54,939	15.76	57,868	20.53

	Three months ended December 31			
	2016	2016	2015	2015
	$000s	$/boe	$000s	$/boe
Oil and gas sales	35,360	38.61	22,630	27.45
Royalties	4,516	4.93	3,612	4.38
Transportation costs	2,462	2.69	1,018	1.23
Production costs	11,088	12.11	14,648	17.77
Operating netback before realized risk management contracts	17,294	18.88	3,352	4.07
Realized gain on risk management contracts	578	0.63	10,334	12.54
Operating netback after realized risk management contracts	17,872	19.51	13,686	16.61

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

(2) Production used when calculating operating netback is determined by the number of days in the period multiplied by average daily production less capitalized production at Blackrod and Onion Lake thermal as disclosed in the Oil and Gas, Oil and Gas Pricing and Oil and Gas Sales section of this MD&A.

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 73% in 2016 to $12.66 per boe from $7.33 per boe in 2015. The increase in the netback is primarily attributable to lower royalties and production costs.

General and Administrative Expenses (G&A)

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	2016	2015	2016	2015
Gross G&A expense	1,774	2,088	7,704	8,810
Operator recoveries	(191)	(268)	(808)	(1,134)
Net G&A expense	1,583	1,820	6,896	7,676
Per boe ($)	1.73	2.21	1.98	2.72

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. The decrease in gross G&A expenses in 2016 compared to 2015 reflects, in part, lower staff compensation costs in 2016 as a result of the implementation of temporary salary reductions and reduced work schedules for our staff during this period of low oil prices as well as lower office rent in 2016 as a result of moving our corporate head office in the second half of the year at a significantly lower rent. Lower operator recoveries in 2016 compared to 2015 is attributable to lower capital spending in 2016.

As oil prices stabilize, salary reductions previously implemented will likely be rescinded and our administrative costs in the future will rise to reflect this change.

Stock-Based Compensation

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2016**	2015	**2016**	2015
Gross stock-based compensation	**700**	1,759	**3,356**	6,073
Recoveries from forfeitures	**(6)**	(3)	**(54)**	(61)
Net stock-based compensation before capitalization	**694**	1,756	**3,302**	6,012
Capitalized stock-based compensation	**–**	–	**–**	(146)
Net stock-based compensation	**694**	1,756	**3,302**	5,866
Per boe ($)	**0.76**	2.13	**0.95**	2.08

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 decrease in gross stock-based compensation in 2016 compared to 2015 is primarily attributable to a decrease in the weighted average market price of the Company's common shares during 2016. In 2016, 310,669 options were exercised, 135,000 options were granted, 478,665 options were forfeited and 2,074,500 options expired. Based on stock options outstanding as at December 31, 2016, the Company has an unamortized stock option compensation expense of approximately $1.0 million, of which $0.9 million is expected to be expensed in 2017 and $0.1 million in 2018.

Finance Costs

	Three months ended December 31		Year Ended December 31	
($000s)	**2016**	2015	**2016**	2015
Gross interest & financing charges	**523**	930	**3,262**	3,498
Capitalized interest & financing charges	**–**	–	**–**	(2,066)
Net interest & financing charges	**523**	930	**3,262**	1,432
Accretion of decommissioning liabilities	**377**	370	**1,461**	1,646
Total finance costs	**900**	1,300	**4,723**	3,078

The decrease in gross interest and financing charges in 2016 compared to 2015 is the result of lower average debt levels and lower interest rates on amounts borrowed in 2016. The average interest rate on advances under the Company's credit facilities was 3.4% in 2016 compared to 3.8% in 2015. This does not include standby fees charged on unutilized amounts of the credit facilities.

All our long-term debt is floating rate debt, so the interest rate charged is based on general market conditions. Additionally, the interest rate charged on our debt is determined, in part, by our debt to EBITDA ratio (as defined in our credit agreement). We have not entered into any financial instruments to fix the interest rate on our debt.

During 2016 we did not capitalize any interest charges. In 2015 we capitalized $2.1 million of interest costs related to debt incurred during the construction of the Onion Lake thermal project.

Depletion and Depreciation

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Depletion and depreciation ($000s)	**11,237**	12,872	**44,626**	51,950
Per boe ($)	**12.27**	15.62	**12.81**	18.42

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 14% in 2016 to $44.6 million from $52.0 million in 2015. On a boe basis, depletion and depreciation expense decreased to $12.81 per boe in 2016 compared to $18.42 per boe in 2015. 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 2016. The depletion rate on this project is below $10 per boe which is lower than the depletion rates for our other producing areas.

Impairment

Cash-generating units ("CGUs") are petroleum and natural gas properties, exploration and evaluation assets and other corporate assets that are aggregated based on their ability to generate largely independent cash inflows and are used for impairment testing. At December 31, 2016, the Company had five CGU's, one for each of our core areas and two CGU's for some of our minor properties. As indicators periodically dictate, the net book values of these CGU's are tested for impairment. At December 31, 2016, the Company performed a review of each of our CGUs for any indicators of impairment and determined the only CGU that had impairment indicators was the Mooney CGU.

At December 31, 2016, the Company performed impairment calculations on the Mooney CGU to assess whether the respective carrying value was recoverable. The recoverable amount used in assessing impairment was calculated at the fair value less costs of disposal using an after tax discounted cash flow model with a discount rate of 11%. At December 31, 2016, the recoverable amount at the Mooney CGU was greater than the carrying value and no impairment loss or reversal was recorded. However, further declines in forecast commodity prices could reduce reserve values and result in the recognition of future asset impairments. Future impairments can also result from changes to reserve estimates, future development costs and capitalized costs.

Income Taxes

BlackPearl did not pay cash income taxes in 2016 and does not expect to pay income taxes in 2017 as we have sufficient tax pools to shelter expected income.

The Company has the following estimated tax pools as at:

($000s, except for left-hand column)	Rate %	**December 31, 2016**	December 31, 2015
Canadian exploration expenses	100	**26,105**	26,274
Canadian development expenses	30	**36,212**	88,248
Canadian oil and gas property expenses	10	**–**	8,508
Undepreciated capital costs	10-30	**247,606**	328,586
Non-capital losses (expiry dates 2027 to 2036)	100	**335,235**	275,594
Share issuance costs	5 years	**1,345**	2,035
Total estimated tax pools		**646,503**	729,245

RESULTS FROM OPERATIONS

	Three months ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Net income (loss) ($000s)	**(2,217)**	(31,172)	**(19,928)**	(46,793)
Per share, basic ($)	**(0.01)**	(0.09)	**(0.06)**	(0.14)
Per share, diluted ($)	**(0.01)**	(0.09)	**(0.06)**	(0.14)

For the year ended December 31, 2016, the Company recognized a net loss of $19.9 million compared to a net loss of $46.8 million in 2015. The decrease in net loss in 2016 is primarily a result of no impairment losses recognized during 2016, increased revenue from higher production volumes and lower production costs, partially offset by lower realized gains on risk management contracts during the year.

	Three months ended December 31		Year Ended December 31	
($000s)	**2016**	2015	**2016**	2015
Cash flow from operating activities (1)	**15,079**	12,179	**42,491**	62,344
Funds flow from operations (2)	**15,798**	10,898	**44,775**	48,962

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

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

Funds flow from operations decreased 9% to $44.8 million during 2016 compared to $49.0 million in 2015. The decrease in funds flow in 2016 is primarily a result of lower realized gains on risk management contracts partially offset by increased revenue from higher production volumes and lower production costs.

Cash flow from operating activities differs from funds flow from operations principally due to the inclusion of decommissioning costs incurred and changes in non-cash working capital. Cash flow from operating activities is lower than funds flow from operations due to decommissioning costs and changes in non-cash working capital of $2.3 million for the year ended December 31, 2016 and $0.7 million for three months ended December 31, 2016.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	**December 31, 2016**	December 31, 2015
Working capital deficiency (surplus)	**4,995**	(11,063)
Long-term debt	**–**	88,000
Net debt (1)	**4,995**	76,937

(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.

At December 31, 2016, the Company had a working capital deficiency of $5 million and no amounts drawn on its $117.5 million credit facilities. We began 2016 with $88 million drawn on our credit facilities. As result of the challenging oil price environment, we felt it was important to maintain a strong financial position and so the majority of our cash flow in 2016 was used to pay down debt and limit capital reinvestment until oil prices improved. In addition, late in the year we sold a royalty interest on production from the majority of our Onion Lake lands for gross proceeds of $55 million. The combination of cash flow from operating activities and the proceeds from the royalty sale allowed us to completely pay off our bank debt at the end of the year.

As result of low commodity prices, during the spring 2016 borrowing base redetermination, our lenders reduced our credit facilities to $117.5 million. During the fall redetermination, our lenders reconfirmed our borrowing base at $117.5 million consisting of a $107.5 million syndicated revolving line of credit and a non-syndicated operating line of credit of $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 based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by May 31, 2017. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

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

($000s, except working capital ratio)	**Year Ended December 31, 2016**	Year Ended December 31, 2015
Current assets per consolidated financial statements	**19,510**	25,537
Add: amount available to be drawn on credit facilities	**117,500**	62,000
Less: current risk management assets	**–**	(10,548)
Current assets for working capital ratio	**137,010**	76,989
Current liabilities per consolidated financial statements	**24,505**	14,474
Less: current risk management liabilities	**(5,507)**	–
Current liabilities for working capital ratio	**18,998**	14,474
Working capital ratio	**7.2**	5.3

The next significant capital project we are planning is the expansion of our Onion Lake thermal project. The second phase of the Onion Lake thermal project is designed for 6,000 bbls/d of oil and capital costs are estimated to be approximately $180 million. Expected cash flow from operating activities and the Company's borrowing capacity on our existing credit facilities is expected to be used to fund a significant portion of the capital costs of the second phase of the Onion Lake thermal project. In addition, we are exploring additional debt financing options to fund the development of the second phase of the Onion Lake thermal project.

During 2016, the Company received regulatory approval for its 80,000 bbls/d commercial Blackrod SAGD project. The Company is planning to build the Blackrod SAGD project in phases, with the first phase likely to be designed for 20,000 bbls/d. We have not completed detailed cost estimates for this phase but our internal estimates suggest initial capital costs will be approximately $800 million. We currently would consider financing options to accelerate the development of this project, including joint venture opportunities.

At December 31, 2016, there were 335,948,895 common shares issued and outstanding and in 2016 the Company issued 310,669 common shares pursuant to the exercise of stock options.

The Company did not pay dividends on its common shares in 2016 and it does not anticipate paying dividends in the near term. Dividends are at the discretion of the Company's board of directors. In addition, the terms and conditions of the Company's existing credit agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

Capital spending decreased in 2016 compared to 2015 as we adjusted our activity levels to reflect a lower oil price environment and used the majority of cash flow from operating activities to reduce debt. Capital expenditures during the year were $10.9 million, with approximately $8.2 million spent at the Onion Lake thermal project related to facility improvements and planning costs for the second phase of the project, $1.1 million spent at Onion Lake related to the drilling of three gross conventional heavy oil wells and $1.6 million spent in other areas.

Capital spending during the fourth quarter of 2016 was $6.2 million, an increase from $1.7 million during the same period in 2015. The main components of the capital spending during the fourth quarter were planning costs for the second phase of the Onion Lake thermal project and drilling of three gross conventional heavy oil wells at Onion Lake.

During the fourth quarter of 2016, the Company sold a royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay approximately 1.75% royalty on production from substantially all of its Onion Lake lands. We have recorded this transaction as a disposition of $40.2 million and a deferred consideration of $14.8 million was recorded on the sale of the royalty that will be recognized over the reserve life at Onion Lake as revenue.

	Three months ended December 31		Year Ended December 31	
($000s)	**2016**	2015	**2016**	2015
Land	**428**	203	**1,172**	988
Seismic	**9**	5	**4**	598
Drilling and completion	**560**	1,059	**3,282**	8,187
Equipment and facilities	**5,079**	358	**6,327**	58,574
Other	**74**	40	**140**	161
Total	**6,150**	1,665	**10,925**	68,508
Property acquisitions	**–**	–	**–**	–
Total capital expenditures	**6,150**	1,665	**10,925**	68,508
Property dispositions	**(40,170)**	–	**(40,170)**	–
Net capital expenditures	**(34,020)**	1,665	**(29,245)**	68,508

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 December 31, 2016. 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)	960	885	687	556	545	–
Electrical service agreement (2)	1,000	585	119	119	119	1,868
Transportation service agreement (3)	135	135	135	33	–	–
Decommissioning liabilities (4)	644	428	347	8,992	1,651	62,242
Capital commitments (5)	5,000	–	–	–	–	–
	7,739	2,033	1,288	9,700	2,315	64,110

(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 $74.3 million as at December 31, 2016. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2016 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair 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

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily priced in US dollars while most of the Company's operating and capital expenditures are denominated in Canadian dollars and (ii) certain deposits, accounts receivable, and accounts payable are denominated in US dollars.

As at December 31, 2016, the Company held US $0.4 million (2015 – US $0.9 million) in cash and cash equivalents. The polymer we purchase for our ASP flood at Mooney is paid in US dollars. Fluctuations in exchange rates will have an impact in the Company's cost of polymer. In 2016, we spent approximately US$0.3 million (2015 – US $3.4 million) on polymer.

In 2016, a $0.01 change in the average exchange rate between the US and Canadian dollar would have changed oil and gas sales by approximately $1.4 million (2015 - $1.9 million). In addition, 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 year would have been approximately $37,000 higher (2015 - $62,000 higher) as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at December 31, 2016. An equal opposite impact would have occurred to net loss had exchange rates been $0.10 higher. The Company does not hedge its foreign currency risk.

Credit Risk

Credit risk is the risk that a third party fails to meet its contractual obligations in a way that could result in the Company incurring a loss. The Company's credit risk is primarily related to its holdings of cash and cash equivalents and trade and other receivables.

As at December 31, 2016, the Company held $5.4 million (2015 - $2.3 million) in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 94% (2015 – 82%) of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited. Cash balances in excess of the Company's day to day requirements are invested in short-term deposits of less than 30 days.

At December 31, 2016, 99% of receivables were from oil and gas marketers related to the sale of our oil and gas production. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate the credit risk associated with these marketers by assessing their financial strength and entering into relationships with larger purchasers with established credit history. During 2016 and 2015, the Company did not experience any collection issues with its marketers.

In 2016, the Company had four customers (2015 – four) which individually accounted for more than 10 percent of its total oil and gas sales. Cumulatively, these customers represented approximately 87% (2015 – 80%) of the Company's total oil and gas sales in 2016.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2016 and 2015, the Company did not experience any collection issues with risk management contracts.

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

Interest Rate Risk

Interest rate risk is the risk that future cash flows of a financial instrument will fluctuate due to changes in interest rates. The Company is exposed to interest rate risk primarily related to its cash and cash equivalents and its long-term debt. The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility due to the floating interest rate charged on advances. For the year ended December 31, 2016, if interest rates had been one percent higher, with all other variables held constant, after tax net loss for the year would have been approximately $788,000 higher (2015 – $207,000 higher).

The Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2016, if interest rates had been one percent higher, with all other variables held constant, after tax net loss for the year would have been approximately $40,000 lower (2015 – $55,000 lower).

Liquidity Risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at December 31, 2016, the Company had $117.5 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

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 and shutting-in high operating costs wells as appropriate. Natural gas currently represents less than 2% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current activities. As the Company's thermal projects continue to be commercially developed, natural gas will continue to become a more significant input cost to the Company.

In 2016, if our average oil wellhead sales price decreased $1.00 with all other variables held constant, our after tax net loss for the year would have been approximately $1.1 million higher (2015 – $2.2 million higher). 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 loss.

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the year ended 2016 or 2015. We do utilize various operating leases in our normal course of business as disclosed under Contractual Obligations and Commitments.

RELATED-PARTY TRANSACTIONS

There was no related-party transactions during the year ended 2016 or 2015 except for key management compensation. Key management compensation has been disclosed in the Company's financial statements (note 15).

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at February 22, 2017, the Company had 336,177,233 common shares outstanding and 26,692,998 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at February 22, 2017, the Company had not drawn any amounts under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $117,480,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of February 22, 2017, the Company does not have any significant pending transactions.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the 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 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 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. A comprehensive discussion of the significant accounting policies adopted by BlackPearl can be found in notes 3 and 4 to the consolidated financial statements.

(a) Significant accounting judgements

Areas where management exercised judgement in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's consolidated financial statements include:

(i) Identification of CGUs

The Company's exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretation by management. Factors considered in the classification of CGUs include integration between assets, shared infrastructure, common sales points, similar geological structure, geographical proximity and the manner in which management monitors and makes decisions about operations. The recoverability of the Company's long-lived assets is assessed at the CGU level and as such; the determination of the CGU could have a significant impact on impairment losses.

(ii) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation (E&E) assets requires judgement in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as proved and probable reserves, drilling results, future capital programs and future operating costs are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or management decides not to continue E&E activity, the unrecoverable E&E costs are charged to exploration expense.

The decision to transfer exploration and evaluation assets to property, plant and equipment is when technical feasibility and commercial viability is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

(iii) Sale of a royalty interest

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

(b) Significant accounting estimates

Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key accounting estimates at the end of the reporting period that if a change were to occur; it could result in a material adjustment to the carrying value of assets and liabilities within the next financial year:

(i) Depletion and reserves

Depletion is based on the proved plus probable reserve estimates as evaluated in accordance with the COGE Handbook. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Future development costs are estimated using assumptions as to the number of wells required to produce commercial reserves, the cost of such wells and associated production facilities and other capital costs. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and changing environment may impact these estimates.

Changes in these variables could significantly impact the reserves estimates which would have significant impact on the impairment test and depletion expense of the Company's long-lived assets. The Company's oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserve evaluators.

Certain costs related to exploration and evaluation assets have been excluded from costs subject to depletion. These costs relate primarily to the Blackrod property and will continue to be classified as E&E until the projects are technically feasible and commercially viable or their value is impaired. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. During the year ended December 31, 2016, the Company received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date. At December 31, 2016, $170.7 million has been excluded from depletion and has been shown separately on the Company's balance sheet.

(ii) Impairment

The carrying value of the Company's long-lived assets is assessed for impairment at least annually and reviewed at each reporting date for indicators that the carrying value of an asset or CGU may be impaired. The recoverable amount of individual assets and CGUs is the greater of their fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Unless indicated otherwise, the recoverable amount used in assessing impairment charges is fair value less costs of disposal. The Company estimates fair value less costs of disposal using an after tax discounted cash flow model which has a number of assumptions. The model uses expected cash flows from proved plus probable reserves and, in certain circumstances, risk adjusted contingent resources as estimated by the Company's third party reserve evaluators. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and subject to variability to changes in forecasted commodity prices. The discount rate applied to the cash flows is also subject to management's judgment and will affect the recoverable amount calculated. Changes in estimates and assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of property, plant and equipment and E&E assets. The summary of the commodity price forecast used to assess CGU impairment in 2016 is disclosed in Note 9 of the consolidated financial statements.

In 2016 and 2015 we had five CGU's, one for each of our core areas and two CGU's for some of our minor properties. At December 31, 2016, the Company performed a review of impairment indicators at each of our CGUs for any indication of impairment and determined the only CGU that had impairment indicators was the Mooney CGU. The Company performed impairment calculations on the Mooney CGU to assess whether the respective carrying value was recoverable. At December 31, 2016, the recoverable amount at the Mooney CGU was greater than the carrying value and no impairment loss or reversal was recorded.

(iii) Decommissioning costs

Provisions are recognized for future decommissioning costs of the Company's E&E and oil and natural gas assets at the end of their economic lives. Decommissioning costs are uncertain and cost estimates can vary in response to many factors including change to relevant legal and regulatory requirements, the emergence of new restoration techniques, or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves and or changes in laws and regulations or their interpretations. Assumptions have been made to estimate the future liability based on past experience and current factors which management believes are reasonable.

However, the actual cost of decommissioning is uncertain and the difference between actual and estimated costs on the consolidated financial statements of future periods may be material. In addition, management determines the appropriate discount rates at the end of each reporting period to determine the present value of the estimated future cash outflows required to settle the decommissioning obligations and may change in response to numerous risk factors including the risk-free rate and future inflation rates.

The following significant assumptions were used for the purpose of estimating the Company's decommissioning liabilities:

	2016	2015
Undiscounted abandonment costs ($000s)	**$74,304**	$77,037
Risk-free rate	**2.0% - 2.3%**	2.2%
Inflation rate	**2.0%**	1.5%
Average years to reclamation	**22**	18

(iv) Deferred tax

Judgment is required in the calculation of current and deferred taxes in applying tax laws and regulations, estimating the time of the reversal of temporary differences and estimating the ability to realize deferred tax assets. Assessing the recoverability of deferred tax assets requires the Company to make estimates related to the expectations of future cash flow from operations. To the extent that future cash flows and taxable income differ from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future. These estimates impact current and deferred tax assets and liabilities, and current and deferred tax expense (recovery).

(v) Stock-based compensation

The Company uses the Black-Scholes pricing model to determine the fair value of stock options granted. The Black-Scholes pricing model requires the Company to make certain assumptions including the expected life of the option, share price volatility, expected forfeitures and anticipated dividends over the life of the options. Changes in these assumptions can materially affect the fair value estimate of the option which can impact stock-based compensation expense, stock-based compensation capitalized and contributed surplus.

(vi) Risk management contracts

The estimated fair value of the Company's risk management contracts by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of risk management contracts include forward benchmark prices, discount rates and forward foreign exchange rates. Changes in estimates and assumptions used in determining the fair value could affect the carrying value of the related assets (liabilities).

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

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

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

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.

In January 2016, the IASB issued amendments to IAS 7, *"Statement of Cash Flows"* ("IAS 7") as part of its disclosure initiative. The amendments require an entity to disclose changes in liabilities arising from financing activities. IAS 7 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The Company will apply amendments to IAS 7 on January 1, 2017 which will have immaterial impact on our consolidated financial statements.

RISK FACTORS

The Company is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. Many of the risk factors and uncertainties are beyond the Company's control and it is impossible to ensure that any exploration drilling program or piloting program will ultimately result in commercial operations.

A full discussion of risk factors affecting the Company can be found in our Annual Information Form for the year ended December 31, 2016. The following explains how material principal and strategic risk factors impact our business:

Financial risks

Volatility of Oil and Natural Gas Prices

The Company's revenues, cash flow, results of operations and financial condition are dependent upon, among other things, the price it receives from the sale of its crude oil and natural gas production. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. These fluctuations in price are in response to factors including, but not limited to, supply and demand for crude oil and natural gas, market uncertainty, world economic conditions, government regulation, political instability, availability of refining capacity and transportation infrastructure, the ability to transport crude to markets, weather conditions and the prices and availability of alternative forms of energy, all of which are generally beyond the control of the Company and can result in a high degree of price volatility. Any decline in oil prices or continued periods of depressed oil prices could have a material adverse effect on BlackPearl's revenues, cash flow, financial condition and the value of the Company's oil and gas reserves.

The Company's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Company's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Company's control. Over 99% of BlackPearl's production is from heavy crude oil and bitumen. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Company's business, financial condition, results of operations and cash flows.

Fluctuations or continued depression in the price of commodities and price differentials may impact the value of the Company's assets, the Company's ability to maintain its business and to fund growth projects, including, but not limited to, the continued development of its oil sands property. Prolonged periods of commodity price volatility may also negatively impact the Company's ability to meet guidance targets.

Crude oil prices were lower in 2016 compared to 2015. WTI oil prices averaged US$43.32 per bbl in 2016, 11% lower than the average of US$48.80 per bbl in 2015. Low oil prices have resulted in the Company deferring development of some of its projects and shutting-in some of its existing production for economic reasons. This has had a material adverse effect on BlackPearl's business, financial condition, results of operations, cash flows and value of its oil and gas reserves. A continued extended decline in the price of crude oil could result in the further delay or cancellation of future drilling programs or construction projects which could also negatively impact BlackPearl's business, financial condition, results of operations, cash flows and value of it oil and gas reserves. Late in 2016 crude oil pricing improved, which was attributable, in part, to the decision by the Organization of Petroleum Exporting Countries (OPEC) and certain non-OPEC countries to reduce their oil output by approximately 1.8 million bbls/d.

The Company conducts an assessment of the carrying value of its assets in accordance with International Financial Reporting Standards, if indicators of impairment or reversal of impairment exist. For the year ended December 31, 2016, no impairment or reversal of impairment was recorded at any of the Company's oil and natural gas assets. If oil and natural gas prices were to decline and remain at low levels for an extended period of time, the carrying value of the Company's assets may be subject to impairment. See the Company's audited consolidated financial statements for the year ended December 31, 2016 for additional financial information related to impairment.

Credit Facility Arrangements

BlackPearl currently has $117.5 million in bank credit facilities. As at December 31, 2016, the Company had no amounts drawn under these facilities. The credit agreement requires BlackPearl to comply with certain covenants and in the event the Company does not meet these covenants BlackPearl may be notified it is in default of the terms of the credit agreement and could be restricted in borrowing additional amounts or it may be required to repay all or a portion of the amounts owing.

In addition, the maximum amount we are permitted to borrow under these credit facilities is subject to periodic review by the lenders, typically semi-annually. BlackPearl's lenders generally review the Company's oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount we are entitled to borrow. In the event the lenders decide to reduce the amount of credit available the Company may be required to repay all or a portion of the amounts owing under these credit facilities.

The Company's ability to make payments on, and to refinance, its future indebtedness, and to fund planned capital expenditures will depend upon, amongst other matters, the Company's ability to generate cash in the future which, in turn, is subject to general economic, financial, competitive, legislative, regulatory and other factors, many of which are beyond the Company's control. If BlackPearl is unable to repay amounts owing under these facilities the lenders could foreclose on the Company's assets and there is no assurance that the assets would be sufficient to repay the full amount owing to all creditors.

Operational risks

Exploration, Development and Production Risks

The long-term success of BlackPearl depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves from exploration, development or acquisition activities, BlackPearl's existing reserves and production will decline over time. Production decline rates will vary by the type of reservoir, age of the wells and other factors and are not necessarily indicative of future performance.

Future increases in BlackPearl's oil and gas reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to generate or raise sufficient capital to make the necessary investments to replace or expand its oil and gas reserves.

There is no assurance that expenditures made on future exploration, development or acquisition by BlackPearl will result in new discoveries of oil or natural gas in commercial quantities.

Uncertainty of Reserve and Contingent Resource Estimates

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond the control of the Company. The reserves, contingent resources and future net cash flow information set forth in this Annual Information Form represent estimates only. While the reserves, contingent resources and future net cash flow information from the Company's properties have been independently evaluated by Sproule in the Sproule Report, these evaluations include a number of assumptions, including, but not limited to, such factors as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, future prices of oil, bitumen and natural gas, operating costs, abandonment and reclamation costs, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flow generated from this production will vary from these evaluations, and these variations could be material.

The present value of the Company's estimated future net revenue disclosed in this Annual Information Form or the Sproule Report should not be construed as the fair market value of the Company's reserves and contingent resources, as applicable.

BlackPearl has limited SAGD production history from its planned SAGD thermal project at Blackrod and the thermal project at Onion Lake. Estimates with respect to reserves and contingent resources that may be developed and produced in the future are often based upon volumetric calculations, and upon analogy to similar types of reserves and contingent resources, rather than those based on actual production history. Subsequent evaluation of the same reserves and contingent resources based upon production history will result in variations, which may be material, in the estimated reserves or contingent resources.

In addition, the reserves and contingent resource estimates have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of heavy crude oil, bitumen and natural gas prices and an increase in actual operating costs experienced on a project may render the recovery of the reserves or contingent resources uneconomic.

A significant portion of BlackPearl's reserves and contingent resources are non-producing or undeveloped. The reserves and contingent resources may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. In addition, not all of the Company's undeveloped reserves and contingent resources may be ultimately produced within the time period BlackPearl has planned, at the costs the Company has budgeted, or at all.

The estimates of reserves, contingent resources and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves, contingent resources and future net revenue for all properties due to the effects of aggregation.

Regulatory risks

Government Regulations

The Company's operations are subject to various levels of government regulation. These regulations include, among other things, matters related to land tenure, drilling, production practices, environmental protection, royalties, carbon tax, marketing and pricing and various taxes and levies. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could have a material adverse impact on the Company's business, financial condition, results of operations and cash flows.

In general, the operations of BlackPearl require licenses and permits from various governmental authorities. The construction and operation of the thermal projects at Blackrod and Onion Lake will require various environmental and other regulatory approvals. Necessary regulatory approvals have been obtained for commercial development for the first and second phase of the Onion Lake thermal project, but future phases of the project will require additional approvals. During 2016, the Company received regulatory and environment approval for the Blackrod commercial development project; however, additional approvals will be required at various stages of developing this project.

There is no assurance that the applicable government authorities will issue the additional approvals required or that a third party will not object to the development of these projects. In addition, once permits are issued there is no assurance that the approvals will not be repealed, or renewed, or that they will contain terms and conditions which make the Company's projects and operations uneconomic or cause the Company to significantly alter its projects and operations.

In response to recent court decisions, the Alberta Energy Regulator has implemented new regulations regarding the ability to transfer leases, licenses, permits, wells and facilities between parties. The AER has increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These new regulations may make it more difficult and costly for producers, such as BlackPearl, to transfer or sell assets to other parties in the future.

Environmental Regulations

Our oil and gas operations are subject to significant environmental local, provincial and federal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with environmental legislation can require significant expenditures and failure to comply with these laws and regulations may result in the assessment of fines and penalties, orders to remediate property contamination and the issuance of injunctions that could limit or prohibit our operations, all of which could have a material impact on the Company. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require BlackPearl to incur costs to remedy such discharge. It is likely the trend to stricter environmental legislation will continue. Changes in environmental laws and regulations may be enacted which could impose higher environmental standards which may increase the cost of our operations and have a material adverse effect on our business, financial condition, results of operations and cash flows. No assurance can be given that future environmental laws and regulations will not adversely impact the Company's ability to develop or operate its projects.

Climate Change Regulations

GHG emission regulations in Canada and the US are evolving, but as these regulations are established they are likely to have a significant impact on organizations involved in the oil sands regions, including BlackPearl. It is difficult to assess the overall impact these regulations will have on BlackPearl at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on our business.

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect BlackPearl's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by BlackPearl or by consumers of BlackPearl's products. The imposition of such measures might negatively affect BlackPearl's costs and prices for BlackPearl's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from BlackPearl's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Various foreign jurisdictions have proposed restrictions or penalties on the importation of emission-intensive fuel sources, which may impact the importation of bitumen from oil sands regions. These restrictions could limit the markets in which BlackPearl and other bitumen producers can sell their oil, which could result in lower sales prices for our heavy crude oil and bitumen. In addition, the Canadian federal government has indicated that it may restrict the export of bitumen to countries with less stringent GHG emissions standards than Canada. If implemented, these restrictions could reduce the markets we are able to sell our bitumen products to, which may result in lower sales prices.

On January 1, 2017, the Alberta government enacted new climate change regulations which included a carbon tax that will be applied across all sectors and a cap on oil sand emissions with a target of 100 megatonnes limit in any year by 2030. Currently the Alberta carbon tax has minimal effect on the Company's earnings and cash flow as the majority of our production comes from Saskatchewan and conventional production in Alberta is exempt from the carbon tax until 2023. The only production the Company has that is subject to the Alberta carbon tax is from the Blackrod property. These new regulations could have a material adverse impact on the Company's earnings and cash flow in the future and could make future capital investments or the Company's operations uneconomic. There is no assurance that these new regulations will not affect the development of the Blackrod SAGD project.

On December 9, 2016, the federal government and all provinces, except Saskatchewan, signed the Pan-Canadian Framework to meet the federal government's 2030 target of a 30% reduction in GHG emissions. The Pan-Canadian Framework requires all provinces and territories to have a carbon pricing scheme in some form by 2018. To date, there has been no legislation introduced on the federal carbon pricing scheme. These new regulations could have a material adverse impact on the Company's earnings and cash flow in the future and could make future capital investments or the Company's operations uneconomic. There is no assurance that these new regulations will not affect the development of the Blackrod SAGD project.

Royalty Regimes

The governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which they own the mineral rights. At Onion Lake, our operations are conducted on the OLCN reserve, and the Company pays royalties to Indian Oil and Gas Canada based on production on reserve lands. The royalty paid at Onion Lake is equivalent to the prevailing government of Saskatchewan royalty rate (without reference to third tier, fourth tier, enhanced oil recovery royalties, holidays or other special incentives).

The government of Alberta has publicly indicated that it intends to review its existing royalty regime from time to time. There can be no assurance that the federal government and the governments of Alberta or Saskatchewan will not adopt a new royalty regime which will make the Company's projects uneconomic or that the regime currently in place will remain unchanged. An increase in royalties would reduce the Company's earnings and cash flow and could make future capital investments or the Company's operations uneconomic.

Other Risks

Information Systems

The Company has become increasingly dependent on information systems to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on information systems, among other things, to estimate quantities of oil and natural gas reserves, process and recorded financial and operating data, analyze seismic and drilling information, process electronic payment transfers and store banking information, monitor and control pipeline and plant equipment, process and store personally identifiable information of our employees, contractors and royalty owners and communicate with employees, stakeholders and business associates. The Company is subject to a variety of information system risks including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of the Company's information systems by third parties or insiders that could result in the disruption of our business operations and/or financial loss.

Management is responsible for overseeing the Company's information systems and although we have security measures and controls in place that are designed to monitor and protect against these threats and mitigate these risks, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. A breach of security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and a disruption to its business activities. Any such event may be material and could have material adverse effect on the financial condition, results of operations and cash flows of the Company.

CONTROL CERTIFICATION

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, means controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief Financial Officer of the Company evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's DC&P were effective as at December 31, 2016.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's DC&P provide a reasonable level of assurance that they are effective, they do not expect that the DC&P will necessarily prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Controls over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

(a) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for the Company. They have, as at the financial year ended December 31, 2016, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, the Company conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2016. Based on this evaluation, the officers concluded that as of December 31, 2016, the Company maintained effective ICFR.

It should be noted that a control system, including the Company's ICFR, 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.

There were no changes in the Company's ICFR during the year ended December 31, 2016 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

2016 GUIDANCE AND 2017 OUTLOOK

	2016		2017
	February Guidance	Actual	Initial Guidance
Production (boe/d)			
Annual average	9,000 - 10,000	10,077	10,000 - 11,000
Cash flow from operating activities ($million) (1)	5 - 10	42	65 - 70
Funds flow from operations (2) ($millions)	5 - 10	45	65 - 70
Capital expenditures ($millions)	10 - 15	11	200
Year-end debt ($millions)	90 - 95	Nil	135 - 140
Pricing Assumptions (annual average)			
Crude oil – WTI	US $35.00	US $43.32	US $54.50
Light/heavy differential	US $14.00	US $13.90	US $14.75
Foreign Exchange (Cdn$ to US$)	0.71	0.76	0.75

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

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

2016 Guidance Compared to Actual

BlackPearl's average oil and gas production of 10,077 boe/day was slightly higher than our February guidance range we provided for the year. This is attributable to the positive performance from the first phase of the Onion Lake thermal project which averaged 5,520 bbls/d during the year.

Cash flow from operating activities and funds flow from operations were above the guidance range primarily as a result of higher crude oil prices. Our actual wellhead price for 2016 was $31.57 per bbl compared to $18.79 per bbl assumed in our guidance. In addition, the low oil price environment led the Company to focus on reducing costs during the year which also partially contributes to the higher actual cash flow and funds flow compared to the guidance provided in 2016.

At December 31, 2016, the Company had no debt, a significant decrease from our February guidance range of $90 to $95 million. The Company's focus on using most of our cash flow to reduce debt levels and using the proceeds on the unbudgeted sale of a royalty interest on our Onion Lake property of $55 million to re-pay long-term debt contributed to the lower than anticipated debt levels at the end of the year.

2017 Initial Guidance

Capital spending in 2017 will be approximately $200 million. Expansion of the Onion Lake thermal project is our main focus for 2017. We have begun preliminary spending on planning and long lead items for the project with a target completion date of mid-2018. In addition to the expansion of the Onion Lake thermal project we also plan to resume drilling on some of our conventional heavy oil projects at John Lake, Onion Lake and other minor project areas.

We are planning to fund a significant portion of the capital costs of the Onion Lake expansion with our funds flow from operations, which we are budgeting to be between $65 and $70 million, and our undrawn credit facilities. We are looking to supplement these sources with $75 to $100 million of additional term debt financing to provide us with financial flexibility during the construction phase. In the event that we are unable to obtain additional financing we will reduce capital spending on our conventional heavy oil projects.

Oil and gas production is expected to average between 10,000 and 11,000 boe/d in 2017. This will include bringing back some of our shut-in production at Onion Lake as well as reactivating phase one of the ASP flood at Mooney.

Sensitivities for 2017 Initial Guidance

The significant factors that would affect forecast funds flows and net income (loss) include commodity prices, heavy oil differentials, exchange rates and production volumes.

($millions)	Funds Flow	Net Income (Loss)
Price change		
CDN$5 per bbl change in our realized oil price	15.9	11.6
CDN$1 per bbl change in production costs	3.7	2.7
Exchange rate		
$0.02 change in US/CDN rate	2.8	2.0
Production rate		
500 bbl per day change	4.1	4.1

FORWARD-LOOKING STATEMENTS

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

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

- Borrowing capacity on our credit facilities is expected to be used to partially fund the expansion of our thermal operations at Onion Lake as discussed in the 2016 Significant Events section;
- The volumes and estimated value of the Company's proved and probable reserves as discussed in the 2016 Significant Events section;
- The volumes and estimated value of the Company's contingent resources as discussed in the 2016 Significant Events section;
- The expected decision by OPEC and certain non-OPEC countries to reduce their oil output as discussed in the Commodity Prices section;
- The expectation of increased oil production in Canada and the need to secure additional pipeline capacity to tidewater as discussed in the Commodity Prices section;
- The estimated change in funds flow from operations for 2016 due to changes in key variables as discussed in the Commodity Prices section;
- With the recent improvement in crude oil prices, the Company plans to selectively bring back on production some of the shut-in wells at Mooney and Onion Lake as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Exploring financing options to accelerate development of the Blackrod SAGD project as discussed in the Oil and Gas Production, Oil and Gas Pricing and Oil and Gas sales section;
- Expectation that royalty rates in 2017 and future periods will increase to reflect the royalty interest sale in late 2016 as discussed in the Royalties section;
- Expectation that administrative costs in the future will rise as salary reductions implemented in the low oil price environment will likely be rescinded as oil prices stabilize as discussed in General and Administrative Expenses section;
- Expected stock-based compensation expense for 2017 and 2018 as discussed in the Stock-based Compensation section;
- Potential future asset impairments or reversals of impairments as discussed in the Impairment section;
- Expected cash taxes to be paid in 2017 as discussed in the Income Taxes section;
- Exploring financing options and estimated costs to expand our Onion Lake thermal project as discussed in the Liquidity and Capital Resources section;

- Exploring financing options and estimated costs to accelerate development of the Blackrod SAGD project as discussed in the Liquidity and Capital Resources section;
- The Company's expectation that it will not be paying dividends in the near term as discussed in the Liquidity and Capital resources section;
- A number of statements under the Risk Factors section since they relate to future conditions and results; 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.

CAUTIONARY STATEMENT ON CONTINGENT RESOURCES

This document makes reference to contingent resources. Contingent resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets and the uncertainty of timing of producing and development of the entire field. See our Annual Information Form for the year ended December 31, 2016 for detailed descriptions of the contingences for each our core areas.

There is no certainty that it will be commercially viable to produce any of the contingent resources. Best estimate (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Other Supplementary Information

1. **List of directors and officers at February 23, 2017**
   a. **Directors:**
      John Craig
      John Festival
      Brian Edgar
      Keith Hill
      Vic Luhowy

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

2. **Financial Information**
   The report for the period ended March 31, 2017 is expected to be published on or before May 15, 2017.

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

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

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

MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements of BlackPearl Resources Inc. and related financial information presented in this financial report are the responsibility of Management and have been approved by the Board of Directors. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards. The Consolidated Financial Statements and related financial information reflect amounts which must, of necessity, be based upon informed estimates and judgments of Management with appropriate consideration to materiality. All financial information contained in the financial report is consistent, where appropriate, with that contained in the Consolidated Financial Statements.

The Company has developed and maintains systems of internal controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguard of assets. Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statements preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent external auditor, has been engaged, as appointed by the shareholders of the Company, to audit and provide their independent audit opinion on the Corporation's financial statements as at and for the year ended December 31, 2016. They review Black Pearl Resources Inc.'s systems of internal controls and conduct their work to the extent they deem appropriate. The auditor's report dated February 22, 2017 and included in the Consolidated Financial Statements, outlines the nature of their audit and expresses their opinion on the financial statements.

The Board of Directors has established an Audit Committee. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the financial statements, and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the interim financial statements prior to their release, as well as annually to review the Company's annual financial statements and Management's discussion and analysis, and to recommend their approval to the Board of Directors. The external auditors have unrestricted access to the Company, the Audit Committee and the Board of Directors.

(signed)

John L. Festival
President and Chief Executive Officer

(signed)

Donald W. Cook
Chief Financial Officer

February 22, 2017

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of BlackPearl Resources Inc.

We have audited the accompanying consolidated financial statements of BlackPearl Resources Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015, and the consolidated statements of comprehensive loss, changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of BlackPearl Resources Inc. and its subsidiaries as at December 31, 2016 and December 31, 2015 and their financial performance and cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
February 22, 2017

Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(audited) (Cdn$ in thousands)	Note	December 31, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents	5	$ 5,368	$ 2,300
Trade and other receivables	6	13,391	10,801
Inventory		46	605
Prepaid expenses and deposits		705	1,283
Fair value of risk management assets	17	–	10,548
		19,510	25,537
Exploration and evaluation assets	8	170,737	169,493
Property, plant and equipment	9	542,157	613,314
		$ 732,404	$ 808,344
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	10	$ 17,950	$ 13,939
Current portion of decommissioning liabilities	11	644	535
Current portion of deferred consideration	7	404	–
Fair value of risk management liabilities	17	5,507	–
		24,505	14,474
Fair value of risk management liabilities	17	452	1,223
Decommissioning liabilities	11	71,122	66,392
Deferred consideration	7	14,425	–
Long-term debt	12	–	88,000
		110,504	170,089
Shareholders' equity			
Share capital	13	970,513	970,134
Contributed surplus		42,994	39,800
Deficit		(391,607)	(371,679)
		621,900	638,255
		$ 732,404	$ 808,344

Commitments and contingencies (note 16)

See accompanying notes to consolidated financial statements

Signed on behalf of the Board:

(signed)

John H. Craig
Chairman and Director

(signed)

Brian D. Edgar
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(audited) *(Cdn$ in thousands, except for per share amounts)*	Note	Year ended December 31, 2016	Year ended December 31, 2015
Revenue			
Oil and gas sales		$ 109,066	$ 96,271
Royalties		(13,785)	(16,190)
Net oil and gas revenue		95,281	80,081
Gain (loss) on risk management contracts	17	(4,490)	25,924
		90,791	106,005
Expenses			
Production		43,334	56,246
Transportation		7,801	3,194
General and administrative		6,896	7,676
Depletion and depreciation	9	44,626	51,950
Impairment of property, plant and equipment	9	–	33,000
Finance costs	18	4,723	3,078
Stock-based compensation	13	3,302	5,866
Foreign currency exchange loss (gain)		46	(141)
		110,728	160,869
Other income			
Interest income		9	53
Loss before income taxes		(19,928)	(54,811)
Income taxes			
Deferred income recovery	14	–	(8,018)
Net and comprehensive loss for the year		$ (19,928)	$ (46,793)
Loss per share			
Basic	13	$ (0.06)	$ (0.14)
Diluted	13	$ (0.06)	$ (0.14)

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(audited) (Cdn$ in thousands)	Year ended December 31, 2016 Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2016	$ 970,134	$ 39,800	$ (371,679)	$ 638,255
Net and comprehensive loss for the year	–	–	(19,928)	(19,928)
Stock-based compensation	–	3,302	–	3,302
Shares issued on exercise of stock options	271	–	–	271
Transfer to share capital on exercise of stock options	108	(108)	–	–
Balance – December 31, 2016	**$ 970,513**	**$ 42,994**	**$ (391,607)**	**$ 621,900**

	Year ended December 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 year	–	–	(46,793)	(46,793)
Stock-based compensation	–	6,012	–	6,012
Balance – December 31, 2015	$ 970,134	$ 39,800	$ (371,679)	$ 638,255

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(audited) (Cdn$ in thousands)	Note	Year ended December 31, 2016	Year ended December 31, 2015
Operating activities			
Net and comprehensive loss for the year		$ (19,928)	$ (46,793)
Items not involving cash:			
Depletion and depreciation	9	44,626	51,950
Impairment of property, plant and equipment	9	–	33,000
Accretion of decommissioning liabilities	18	1,461	1,646
Stock-based compensation	13	3,302	5,866
Foreign exchange loss		31	8
Deferred income recovery	14	–	(8,018)
Unrealized loss on risk management contracts	17	15,283	11,303
Decommissioning costs incurred	11	(580)	(531)
Changes in non-cash working capital	18	(1,704)	13,913
Cash flow from operating activities		42,491	62,344
Financing activities			
Proceeds on issue of common shares, net of costs		271	–
Proceeds on issue of long-term debt	12	–	68,000
Repayment of long-term debt	12	(88,000)	(9,000)
Cash flow from (used) in financing activities		(87,729)	59,000
Investing activities			
Capital expenditures - exploration and evaluation assets	8	(967)	(3,477)
Capital expenditures - property, plant and equipment	9	(9,958)	(64,885)
Proceeds from disposition of property, plant and equipment	7	55,000	–
Changes in non-cash working capital	18	4,216	(53,451)
Cash flow from (used) in investing activities		48,291	(121,813)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		15	(149)
Increase (decrease) in cash and cash equivalents		3,068	(618)
Cash and cash equivalents, beginning of year		2,300	2,918
Cash and cash equivalents, end of year		$ 5,368	$ 2,300

See accompanying notes to consolidated financial statements

(tabular amounts in thousands of Cdn$, except as noted)

(audited)

1. GENERAL INFORMATION

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

2. BASIS OF PREPARATION

The Company prepared its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). These consolidated financial statements were approved and authorized for issuance by the Company's Board of Directors ("the Board") on February 22, 2017.

3. SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used in the preparation of these consolidated financial statements are described below.

Basis of measurement

The consolidated financial statements have been prepared on a historical cost basis except for risk management contracts which are measured at fair value.

Consolidation

The consolidated financial statements of the Company comprise the financial statements of BlackPearl and its subsidiaries as at December 31, 2016. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated in full on consolidation. Subsidiaries are entities controlled by the Company. The Company controls an entity when it is exposed to, or has rights to, variable returns from its investment with the entity and has the ability to affect those returns through its power over the entity.

Joint arrangements

A portion of the Company's activities are owned and operated jointly with other parties. All the Company's joint arrangements are classified as joint operations. These consolidated financial statements reflect only the Company's appropriate share of the joint operation's controlled assets and liabilities it has incurred, its share of any liabilities jointly incurred, income from the sale or use of its share of the joint operation's output, together with its share of expenses incurred by the joint operation and any expenses it incurs in relation to its interest in the joint arrangement and a share of production in such activities.

Financial instruments

The Company's financial instruments include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets and liabilities, accounts payable and accrued liabilities and long-term debt. Financial instruments are initially classified into one of the following five categories: fair value through profit or loss, loans and receivables, held to maturity investments, available-for-sale financial assets or financial liabilities measured at amortized costs. Financial instruments are initially measured at fair value, except in the case of financial liabilities measured at amortized costs which are initially measured at fair value less directly attributable transaction costs.

The subsequent measurement of financial assets and financial liabilities depends on their classification as described below:

(i) Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss are either ‘held-for-trading’ or have been ‘designated at fair value through profit or loss’. In both cases the financial assets and liabilities are measured at fair value with changes in fair value recognized in net income.

(ii) Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization.

(iii) Held-to-maturity

Held-to-maturity investments are measured at amortized cost at the settlement date using the effective interest method of amortization.

(iv) Available-for-sale

Available for sale financial instruments are measured at fair value, with changes in the fair value recognized in other comprehensive income or loss. When an active market is non-existent, fair value is determined using a valuation technique. When fair value cannot be reliably measured, such assets are carried at cost.

(v) Financial liabilities at amortized cost

These financial liabilities are initially measured at fair value, net of any transactions costs. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method of amortization.

The Company has no financial assets or financial liabilities that give rise to other comprehensive income or loss. Financial assets and financial liabilities are offset and the net amount reported in the consolidated balance sheet if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis. Financial assets and financial liabilities are classified as current if they are assumed to be settled within one year; otherwise they are classified as non-current.

Risk management contracts

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 or loss.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less.

Inventory

Inventory is carried at the lower of cost and net realizable value on a weighted average cost basis. The cost of inventory includes all cost incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

Exploration and evaluation costs

Exploration and evaluation (E&E) activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. E&E costs are capitalized for projects prior to their technical feasibility and commercial viability being determined. These costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses including remuneration of production personnel and supervisory management, the projected decommissioning costs and any activities in relation to evaluating the technical feasibility and commercial viability of extracting mineral resources. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to net income as exploration and evaluation expense. Assets classified as E&E are not depleted or depreciated.

All capitalized E&E costs are subject to technical feasibility and commercial viability, management review and a review for indicators of impairment at each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the resource. When an E&E area is determined not to be technically feasible or commercially viable, or the Company decides not to continue with its activity, the unrecoverable E&E costs are charged to net income as exploration and evaluation expense.

Once technical feasibility and commercial viability are confirmed, the E&E asset is first assessed for impairment and if required, any impairment loss is recognized. The remaining carrying amount of the E&E asset is then reclassified to property, plant and equipment. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

Property, plant and equipment

Property, plant and equipment are stated at cost, less accumulated depletion and depreciation and accumulated impairment losses. All costs directly associated with the development of petroleum and natural gas reserves are capitalized on an area by area basis. Development costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include proved property acquisitions, development drilling, completion, gathering and infrastructure, decommissioning costs and transfers of exploration and evaluation assets. Borrowing costs incurred during the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use.

Costs accumulated within each area are depleted using the unit-of-production method based on proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved and probable reserves. These estimates are reviewed by independent reserve engineers at least annually.

Corporate assets consist primarily of office equipment, leasehold improvements and computer equipment/software and are stated at cost less accumulated depreciation. Depreciation of these corporate assets is calculated using the declining-balance method.

For property dispositions, measurement is at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. Where the exchange is measured at fair value, a gain or loss is recognized in net income. Any deferred consideration recorded on property dispositions are recognized as revenue in the statement of comprehensive income or loss over the reserve life.

At each reporting period, a review is done to ensure that the asset's residual values, useful lives and methods of depletion/depreciation are appropriate. If necessary, changes are made prospectively.

Cash generating unit (CGU)

The Company's exploration and evaluation costs and property, plant and equipment costs are aggregated into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash inflows that are largely independent of cash inflows from other assets or groups of assets.

Impairment

Non-financial assets

The carrying value of the Company's non-financial assets is assessed for impairment at least annually and reviewed at each reporting date for indicators that the carrying value of an asset or CGU may be impaired. These indicators include, but are not limited to, extended decreases in prices or margins for oil and gas commodities or products, market capitalization, a significant downward revision in estimated reserves or an upward revision in future development costs. If indicators of impairment exist, the recoverable amount of the asset or CGU is estimated.

The recoverable amount of individual assets and CGUs is the greater of their fair value less costs of disposal and its value in use. Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction, less the costs of disposal. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. Unless indicated otherwise, the recoverable amount used in assessing impairment charges is fair value less costs of disposal. The Company estimates fair value less costs of disposal using an after tax discounted cash flow model. If the carrying value of the asset or CGU exceeds the recoverable amount, the asset or CGU is considered impaired and is written down to its recoverable amount with impairment recognized in net income.

An assessment is made at each reporting date to determine whether there is an indication that previously recognized impairment losses no longer exist or have decreased. If indication exists, the Company estimates the asset's or CGU's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income. The recoverable amount is limited to the original carrying amount less depletion and depreciation as if no impairment had been recognized for the asset or CGU for prior periods.

Financial assets

The Company will assess at each reporting period whether there is any objective evidence that a financial asset, other than those measured at fair value, is impaired. A financial asset is deemed to be impaired if there is objective evidence of impairment as a result of one or more events that has occurred since the initial recognition of the asset that has a negative impact on the estimated future cash flows of the financial asset.

When assessing impairment of the Company's financial assets carried at amortized cost, the carrying value of the financial assets is compared to the present value of estimated future cash flows, discounted using the instrument's original effective interest rate. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in income or loss.

Decommissioning liabilities

Decommissioning liabilities include present legal or constructive obligations as a result of past events where the Company will be required to retire tangible long-lived assets such as producing well sites and facilities. The obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. When the liability is initially recognized, the amount represents management's estimate of the present value of the estimated future expenditures to abandon and reclaim the Company's net ownership in wells and facilities as well as an estimate of the future timing of the costs to be incurred. When a liability is recorded, the carrying amount of the related asset is increased by the same amount.

These costs are subsequently depleted as part of the costs of the item of property, plant and equipment. Any changes in the estimated timing of the decommissioning, or decommissioning costs estimates, or changes in the discount rate used to calculate the present value of future expenditures are accounted for prospectively by recording an adjustment to the provision for decommissioning liabilities and a corresponding adjustment to property, plant and equipment.

Increases in decommissioning liabilities resulting from the passage of time are recorded as a finance cost in the consolidated statement of comprehensive income or loss. Actual expenditures incurred are charged against the accumulated decommissioning liability as incurred. The provision is re-measured at each reporting period in order to reflect the inflation and risk-free rate in effect at that time.

Stock-based compensation

Periodically, the Company will grant stock options in exchange for the provision of services from certain employees, directors, officers and consultants. The Company follows the fair value method of valuing stock option grants using the Black-Scholes pricing model. Stock-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the qualifying portion of the stock-based compensation directly attributable to the development activities of exploration and evaluation and property, plant and equipment assets with a corresponding decrease to stock-based compensation expense. At the time the stock options are exercised, the issuance of common shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Contingencies

When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow; a liability is recognized in the consolidated financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed when the possibility is considered more than remote but not yet probable, where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow. Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the consolidated financial statements.

Income tax

Income tax expense is comprised of current and deferred tax. Income tax is recognized in the statement of comprehensive income or loss except to the extent that it relates to items recognized directly in equity, in which case the income tax is also recognized directly in equity.

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Company operates and generates taxable income.

In general, deferred tax is recognized using the balance sheet method, providing for temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements at the reporting date. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the balance sheet date and are expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered and any deferred income tax assets and/or liabilities are presented as non-current.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and the deferred tax amounts relate to income taxes levied by the same tax authority on the same taxable entity. The Company intends to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Revenue recognition

Revenue is recognized when the significant risks and rewards of ownership have been transferred to the customer, the revenue can be reliably measured and it is probable that the economic benefits will flow to the Company. This takes place once delivery has occurred, the sales price is fixed or determinable and collectability is reasonably assured. Risk and rewards of ownership have been transferred to the customer at the time the product is shipped and delivered to the customer and, depending on the delivery conditions, title and risk have passed to the customer and acceptance of the product, when contractually required, has been obtained. Revenue is measured at the fair value of the consideration received or receivable, excluding discounts, sales taxes, excise duties and similar levies based on the price specified in the sales contract.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction, net of tax, from equity.

Income (loss) per share

Basic income (loss) per share is calculated by dividing the net income (loss) for the year attributable to equity owners of BlackPearl by the weighted average number of common shares outstanding during the year. Diluted income (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments, such as stock options, using the treasury stock method. The treasury stock method assumes proceeds from dilutive instruments are used to purchase common shares at the average market price during the year.

Finance costs

The Company's finance costs include interest and financing charges, accretion of decommissioning liabilities and debt financing costs. Interest and financing charges are recognized using the effective interest method.

Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use are capitalized as part of the cost of the respective assets until such time the asset is substantially ready for its intended use. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds. All other borrowing costs are recognized in the statement of comprehensive income or loss in the period in which they are incurred.

Foreign currency translation

Items included in the financial statements are measured using the currency of the primary economic environment in which the Company operates (the "functional currency"). The financial statements are presented in Canadian dollars, which is the Company's functional currency.

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. At each balance sheet date, monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in income or loss.

Accounting standards issued but not yet applied

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

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

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

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.

In January 2016, the IASB issued amendments to IAS 7, "Statement of Cash Flows" ("IAS 7") as part of its disclosure initiative. The amendments require an entity to disclose changes in liabilities arising from financing activities. IAS 7 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The Company will apply amendments to IAS 7 on January 1, 2017 which will have immaterial impact on our consolidated financial statements.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the 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 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 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.

(a) Significant accounting judgements

Areas where management exercise judgement in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's consolidated financial statements include:

(i) Identification of CGUs

The Company's exploration and evaluation assets and property, plant and equipment assets are aggregated into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash inflows that are largely independent of cash inflows from other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretation by management. Factors considered in the classification of CGUs include integration between assets, shared infrastructure, common sales points, similar geological structure, geographical proximity and the manner in which management monitors and makes decisions about operations. The recoverability of the Company's long-lived assets is assessed at the CGU level and as such; the determination of the CGU could have a significant impact on impairment losses.

(ii) Exploration and evaluation assets

The application of the Company's accounting policy for E&E assets requires judgement in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as proved and probable reserves, drilling results, future capital programs and future operating costs are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or management decides not to continue E&E activity, the unrecoverable E&E costs are charged to exploration expense.

The decision to transfer exploration and evaluation assets to property, plant and equipment is when commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained.

(iii) Sale of a royalty interest

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

(b) Significant accounting estimates

Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key accounting estimates at the end of the reporting period that if a change were to occur; it could result in a material adjustment to the carrying value of assets and liabilities within the next financial year:

(i) Depletion and reserves

Depletion is based on the proved plus probable reserve estimates as evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook (COGEH). The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Future development costs are estimated using assumptions as to the number of wells required to produce commercial reserves, the cost of such wells and associated production facilities and other capital costs. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and changing environment may impact these estimates.

Changes in these variables could significantly impact the reserves estimates which would have significant impact on the impairment test and depletion expense of the Company's long-lived assets. The Company's oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserve evaluators.

(ii) Impairment

The carrying value of the Company's non-financial assets is assessed for impairment and reversal of impairment at each reporting date for indicators that the carrying value of an asset or CGU may be impaired. The recoverable amount of individual assets and CGUs is the greater of their fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Unless indicated otherwise, the recoverable amount used in assessing impairment charges is fair value less costs of disposal. The Company estimates fair value less costs of disposal using an after tax discounted cash flow model which has a number of assumptions. The model uses expected cash flows from proved plus probable reserves and, in certain circumstances, risk adjusted contingent resources as estimated by the Company's third party reserve evaluators. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and subject to variability to changes in forecasted commodity prices. The discount rate applied to the cash flows is also subject to management's judgment and will affect the recoverable amount calculated. Changes in estimates and assumptions used in determining the recoverable amount could affect the carrying value of the related assets. The discount rate used to assess CGU impairment and reversal of impairment in 2016 is disclosed in Note 9 of the consolidated financial statements.

Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of property, plant and equipment and E&E assets. The summary of the commodity price forecast used to assess CGU impairment and reversal of impairment in 2016 is disclosed in Note 9 of the consolidated financial statements.

(iii) Decommissioning liabilities

Provisions are recognized for future decommissioning costs of the Company's E&E and oil and natural gas assets at the end of their economic lives. Decommissioning costs are uncertain and cost estimates can vary in response to many factors including change to relevant legal and regulatory requirements, the emergence of new restoration techniques, or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves and or changes in laws and regulations or their interpretations. Assumptions have been made to estimate the future liability based on past experience and current factors which management believes are reasonable. However, the actual cost of decommissioning is uncertain and the difference between actual and estimated costs on the consolidated financial statements of future periods may be material. In addition, management determines the appropriate discount rates at the end of each reporting period to determine the present value of the estimated future cash outflows required to settle the decommissioning obligations and may change in response to numerous risk factors including the risk-free rate and future inflation rates. The inflation factor and discount rates used in determining decommissioning liabilities at December 31, 2016 are disclosed in Note 11 of the consolidated financial statements.

(iv) Deferred tax

Judgment is required in the calculation of deferred taxes in applying tax laws and regulations, estimating the timing of reversals of temporary differences and estimating the ability to realize deferred tax assets. Assessing the recoverability of deferred tax assets requires the Company to make estimates related to the expectations of future cash flows from operations. To the extent that future cash flows and taxable income differ from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future. These estimates impact deferred tax assets and liabilities, and deferred tax expense (recovery).

(v) Stock-based compensation

The Company uses the Black-Scholes option pricing model to determine the fair value of stock options granted. The Black-Scholes option pricing model requires the Company to make certain assumptions including the expected life of the option, share price volatility, expected forfeitures and anticipated dividends over the life of the options. Changes in these assumptions can materially affect the fair value estimate of the option which can impact stock-based compensation expense, stock-based compensation capitalized and contributed surplus.

(vi) Risk management contracts

The estimated fair value of the Company's risk management contracts by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of risk management contracts include forward benchmark prices, discount rates and forward foreign exchange rates. Changes in estimates and assumptions used in determining the fair value could affect the carrying value of the related assets (liabilities).

5. CASH AND CASH EQUIVALENTS

	2016	2015
Cash at financial institutions	$ 5,368	$ 2,300

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of December 31, 2016, US $0.4 million (2015 – US $0.9 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

6. TRADE AND OTHER RECEIVABLES

	2016	2015
Trade accounts receivable	$ 13,206	$ 6,264
Receivables from joint operation partners	328	304
Allowance for doubtful accounts	(285)	(285)
Net accounts receivable	13,249	6,283
Receivable from risk management contracts	48	4,228
Other receivables	94	290
Total trade and other receivables	$ 13,391	$ 10,801

Aging of trade and other receivables are as follows:

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

At December 31, 2015	Current	31 to 60 days	61 to 90 days	Over 90 days	Total
Trade accounts receivable	$ 6,264	$ –	$ –	$ –	$ 6,264
Receivables from joint operation partners	3	6	2	293	304
Allowance for doubtful accounts	–	–	–	(285)	(285)
Receivable from risk management contracts	4,228	–	–	–	4,228
Other receivables	196	–	–	94	290
Total trade and other receivables	$ 10,691	$ 6	$ 2	$ 102	$ 10,801

7. SALE OF A ROYALTY INTEREST

On December 1, 2016, the Company sold a royalty interest on its Onion Lake property for cash proceeds of $55 million whereby the Company will pay an approximate 1.75% royalty on production from substantially all of its Onion Lake lands. The holder of the royalty has the option of either being paid in cash or in kind. The royalty has no associated commitments to develop future expansions or projects.

We have recorded this transaction as a disposition of $40.2 million to property, plant and equipment (Note 9) and a $14.8 million deferred consideration was recorded on the sale of the royalty that will be recognized over the reserve life at Onion Lake as revenue. At December 31, 2016, the current portion of deferred consideration is $0.4 million.

8. EXPLORATION AND EVALUATION ASSETS

At January 1, 2015	$ 166,344
Expenditures	3,477
Change in decommissioning provision	(328)
At December 31, 2015	169,493
Expenditures	967
Change in decommissioning provision	277
At December 31, 2016	$ 170,737

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD pilot project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During 2016, no assets were considered to be impaired.

The transfer of exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established. Technical feasibility and commercial viability is established when significant proved reserves are recognized and regulatory approval has been obtained. During the year ended December 31, 2016, the Company received regulatory approval for Blackrod SAGD commercial development; however, significant proved reserves have yet to be recognized to date.

During the year ended December 31, 2016, the Company capitalized net operating revenues totalling a gain of $0.1 million (2015 – loss of $2.1 million) related to the Blackrod SAGD pilot project. The Company did not capitalize any general and administrative costs related to exploration activities during the year ended December 31, 2016 (2015 – $Nil).

9. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2015	$ 1,170,170	$ 3,496	$ 1,173,666
Expenditures	64,874	11	64,885
Capitalized stock-based compensation	146	–	146
Change in decommissioning provision	5,455	–	5,455
At December 31, 2015	1,240,645	3,507	1,244,152
Expenditures	9,825	133	9,958
Change in decommissioning provision	3,681	–	3,681
Dispositions (Note 7)	(40,170)	–	(40,170)
At December 31, 2016	$ 1,213,981	$ 3,640	$ 1,217,621
Accumulated depletion and depreciation			
At January 1, 2015	$ 543,574	$ 2,314	$ 545,888
Depletion and depreciation	51,781	169	51,950
Impairment	33,000	–	33,000
At December 31, 2015	628,355	2,483	630,838
Depletion and depreciation	44,476	150	44,626
At December 31, 2016	$ 672,831	$ 2,633	$ 675,464
Net book value			
December 31, 2015	$ 612,290	$ 1,024	$ 613,314
December 31, 2016	$ 541,150	$ 1,007	$ 542,157

The calculation of depletion for the year ended December 31, 2016 included estimated future development costs of $814 million (2015 – $596 million) associated with the development of the Company's proved plus probable reserves. During the year ended December 31, 2016, the Company did not capitalize any borrowing costs related to development activities (2015 – $2.1 million). The Company did not capitalize any general and administrative costs related to development activities during the year ended December 31, 2016 (2015 – $Nil).

At December 31, 2016, the Company performed a review of each of our CGUs for any indicators of impairment. The Company has five CGU's (2015 – five), one for each of our core areas of Onion Lake, Mooney and Blackrod and two CGU's for some of our minor properties. The Company determined the only CGU that had impairment indicators at December 31, 2016 was the Mooney CGU.

At December 31, 2016, the Company performed impairment calculations on the Mooney CGU to assess whether the respective carrying value was recoverable. The recoverable amount used in assessing impairment was calculated at the fair value less costs of disposal using an after tax discounted cash flow model with a discount rate of 11%. At December 31, 2016, the recoverable amount at the Mooney CGU was greater than the carrying value and no impairment loss or reversal was recorded (2015 – $33 million impairment at the Mooney CGU).

The estimated recoverable amount of the Mooney CGU is sensitive to discount rate and forward price estimates. Changes to these assumptions, assuming all other variables remained constant, would have the following earnings impact. A one percent increase in the assumed discount rate would result in an impairment loss of $12.9 million at the Mooney CGU. A ten percent decrease in the forward commodity price estimates would result in an impairment loss of $51.5 million at the Mooney CGU. A one percent increase in the assumed discount rate or a ten percent decrease in the commodity price estimates would not result in impairment at any of the Company's other CGUs in 2016.

The following represents the prices that were used in the December 31, 2016 impairment tests:

	Price Forecasts (1)			
Year	WTI (2) Cushing 40° API	WCS (3) 20.5° API	Alberta AECO-C Spot	Exchange rate
	(US$/bbl)	(CDN$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2017	55.00	53.12	3.44	0.78
2018	65.00	61.85	3.27	0.82
2019	70.00	64.94	3.22	0.85
2020	71.40	66.93	3.91	0.85
2021	72.83	68.27	4.00	0.85
2022	74.28	69.64	4.10	0.85
2023	75.77	71.03	4.19	0.85
2024	77.29	72.45	4.29	0.85
2025	78.83	73.90	4.40	0.85
2026	80.41	75.38	4.50	0.85
2027	82.02	76.88	4.61	0.85
	Escalation rate of 2.0% thereafter (4)			

(1) The benchmark prices listed above as determined by the Company's independent reserve evaluators, Sproule Unconventional Limited, are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment test for each CGU.

(2) West Texas Intermediate (a light oil reference price).

(3) Western Canadian Select (a heavy oil reference price.)

(4) Percentage change represents the change in each year after 2027 to the end of the reserve life.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2016	2015
Trade payables and accrued liabilities	$ 16,879	$ 13,371
Payables to joint operation partners	275	218
Other payables	796	350
Total accounts payable and accrued liabilities	$ 17,950	$ 13,939

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

11. DECOMMISSIONING LIABILITIES

The Company's decommissioning liability is an estimate of the reclamation and abandonment costs arising from the Company's ownership interest in oil and gas assets, including well sites, gathering systems, batteries, processing and thermal facilities. The total undiscounted amount of the estimated cash flows required to settle the Company's liabilities is approximately $74.3 million (2015 – $77.0 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2.0% (2015 – 1.5%) and discounted using a risk-free rate of 2.0% to 2.3% (2015 – 2.2%) based on expected settlement date. Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement. The revision in the inflation rate in 2016 resulted from the current and forecasted economic climate and is consistent with estimates in the Company's independent reserve report.

Changes to the decommissioning liability were as follows:

	2016	2015
Decommissioning liability, beginning of the year	$ 66,927	$ 60,683
New liabilities recognized	103	15,067
Decommissioning costs incurred	(580)	(531)
Change in estimated costs of decommissioning	(2,813)	(7,670)
Change in inflation rate	6,864	(4,883)
Change in discount rate	(196)	2,615
Accretion expense	1,461	1,646
Decommissioning liability, end of the year	71,766	66,927
Less current portion of decommissioning liability	(644)	(535)
Non-current portion of decommissioning liability	$ 71,122	$ 66,392

12. LONG-TERM DEBT

At December 31, 2016, the Company had credit facilities of $117.5 million, consisting of a $107.5 million syndicated revolving line of credit (2015 – $140 million) and a non-syndicated operating line of credit of $10 million (2015 – $10 million). At December 31, 2016, the Company had not drawn any amounts (2015 – $88 million) under these credit facilities and had letters of credit issued in the amount of $20,000 (2015 – $20,000); leaving $117.5 million (2015 – $62 million) available to be drawn under these facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay the difference. The next scheduled Borrowing Base redetermination is to occur by May 31, 2017. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 27, 2017. If the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding would convert to a term loan that would be due and payable in full by May 26, 2018.

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

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities 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 7.2:1 at December 31, 2016 (2015 – 5.3:1) and, accordingly, was in compliance with this covenant at December 31, 2016.

13. 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 and December 31, 2015	335,638,226	$ 970,134
Shares issued on exercise of stock options	310,669	271
Transferred from contributed surplus on exercise of stock options	–	108
Balance as at December 31, 2016	335,948,895	$ 970,513

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company. 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 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, 2015	20,916,335	3.00
Granted	11,458,500	0.84
Forfeited	(666,666)	2.71
Expired	(2,053,000)	4.89
Outstanding at December 31, 2015	29,655,169	2.04
Granted	135,000	0.93
Exercised	(310,669)	0.87
Forfeited	(478,665)	3.04
Expired	(2,074,500)	5.18
Outstanding at December 31, 2016	26,926,335	1.79

Options outstanding and exercisable as at December 31, 2016 are summarized below:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices ($)	Number of Options Outstanding	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)	Number of Options Exercisable	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)
0.71 – 1.50	11,066,167	0.84	3.48	4,868,391	0.80	3.61
1.51 – 3.00	14,205,668	2.31	2.18	11,687,022	2.24	2.19
3.01 – 3.87	1,654,500	3.73	0.48	1,654,500	3.73	0.48
	26,926,335	1.79	2.61	18,209,913	1.99	2.41

The fair value of common share options granted is estimated on the date of grant using the Black-Scholes option pricing model. During the year ended December 31, 2016, 135,000 options were granted (2015 – 11,458,500). The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	Year ended December 31, 2016	Year ended December 31, 2015
Risk free interest rate (%)	0.6	0.7
Dividend yield (%)	0.0	0.0
Expected life (years)	3.7	3.7
Expected volatility (%)	55.2	53.9
Forfeiture rate (%)	11.3	12.9
Weighted average fair value of options	$ 0.38	$ 0.34

(d) Stock-based Compensation

	Year ended December 31, 2016	Year ended December 31, 2015
Gross stock-based compensation	$ 3,356	$ 6,073
Recoveries from forfeitures	(54)	(61)
Net stock-based compensations before capitalization	3,302	6,012
Stock-based compensation capitalized to property, plant and equipment	–	(146)
Net stock-based compensation	$ 3,302	$ 5,866

(e) Loss per Share

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

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

	Year ended December 31, 2016	Year ended December 31, 2015
Net and comprehensive loss	$ (19,928)	$ (46,793)
Weighted average number of common shares – basic	335,665	335,638
Dilutive effect:		
Outstanding options	–	–
Weighted average number of common shares – diluted	335,665	335,638
Basic loss per share	$ (0.06)	$ (0.14)
Diluted loss per share	$ (0.06)	$ (0.14)

For the year ended December 31, 2016, the Company used a weighted average market closing price of $1.24 (2015 – $0.93) per share to calculate the dilutive effect of stock options. For the year ended December 31, 2016, all outstanding options were anti-dilutive (2015 – all outstanding options were anti-dilutive) and were not included in the calculation of diluted loss per share.

14. INCOME TAXES

(a) Income tax expense

The provision for income taxes reflects an effective income tax rate which differs from federal and provincial statutory tax rates. The main differences are as follows:

	Year ended December 31, 2016	Year Ended December 31, 2015
Loss before income taxes	$ (19,928)	$ (54,688)
Corporate income tax rate	27.00%	26.40%
Computed income tax recovery	$ (5,381)	$ (14,438)
Increase (decrease) resulting from:		
Changed in unrecognized deferred income tax assets	6,042	1,925
Prior period adjustment	(1,448)	3,094
Non-deductible expenses	901	1,549
Changed in enacted tax rates	–	(148)
Other	(114)	–
Income tax recovery	$ –	$ (8,018)

(b) Deferred income tax

The movement in deferred income tax liabilities and assets is as follows:

	January 1, 2016	(Charged)/credited to income (loss)	December 31, 2016
Deferred income tax assets:			
Decommissioning liabilities	$ 18,001	$ 1,304	$ 19,305
Income tax losses carried forward	74,411	16,103	90,514
Deferred consideration	–	4,004	4,004
Risk management contracts	–	1,609	1,609
Share issue costs	549	(186)	363
	92,961	22,834	115,795
Deferred income tax liabilities:			
Property, plant and equipment	(90,443)	(25,352)	(115,795)
Risk management contracts	(2,518)	2,518	–
	(92,961)	(22,834)	(115,795)
Net deferred income tax assets (liabilities)	$ –	$ –	$ –

	January 1, 2015	(Charged)/credited to income (loss)	December 31, 2015
Deferred income tax assets:			
Decommissioning liabilities	$ 15,509	$ 2,492	$ 18,001
Income tax losses carried forward	55,390	19,021	74,411
Share issue costs	694	(145)	549
	71,593	21,368	92,961
Deferred income tax liabilities:			
Property, plant and equipment	(74,316)	(16,127)	(90,443)
Risk management contracts	(5,295)	2,777	(2,518)
	(79,611)	(13,350)	(92,961)
Net deferred income tax assets (liabilities)	$ (8,018)	$ 8,018	$ –

(c) Unrecognized deferred tax assets

As at December 31, 2016, the Company had $335 million (2015 – $276 million) non-capital losses set to expire no earlier than 2026.

Certain deferred income tax assets have not been recognized as it not probable that future taxable profit will be available against which the benefits can be utilized. These tax assets relate to non-producing assets located in the United States and certain resources pools in Canada that are restricted through successor rules.

The Company has temporary differences associated with its investments in its foreign subsidiaries. The Company has no deferred tax liabilities in respect of these temporary differences.

The Company had no current tax payable in 2016 or 2015.

15. SALARY AND OTHER COMPENSATION EXPENSES

(a) Employee compensation expenses

The following table provides a breakdown of gross salaries, benefits, stock-based compensation and other compensation expenses included in the consolidated statements of comprehensive loss:

	Year ended December 31, 2016	Year Ended December 31, 2015
Production expense [1]	$ 1,438	$ 1,451
General and administrative expense	3,699	4,138
Stock-based compensation	3,302	5,866
	$ 8,439	$ 11,455

(1) Excludes amounts paid to contractors and consultants.

(b) Key management compensation

Key management includes the Company's directors and officers. At December 31, 2016, directors and senior management consisted of eight individuals (2015 – eight individuals).

The following table summarizes the compensation of key management:

	Year ended December 31, 2016	Year Ended December 31, 2015
Salary and employee benefits	$ 1,095	$ 1,196
Stock-based compensation	1,563	2,844
	$ 2,658	$ 4,040

16. COMMITMENTS AND CONTINGENCIES

	2017	2018	2019	2020	2021	Thereafter
Operating leases [1]	$ 960	$ 885	$ 687	$ 556	$ 545	$ –
Electrical service agreement [2]	1,000	585	119	119	119	1,868
Transportation service agreement [3]	135	135	135	33	–	–
Decommissioning liabilities [4]	644	428	347	8,992	1,651	62,242
Capital commitments [5]	5,000	–	–	–	–	–
Total	$ 7,739	$ 2,033	$ 1,288	$ 9,700	$ 2,315	$ 64,110

(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 $74.3 million as at December 31, 2016. 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.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2016 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, accounts payable and accrued liabilities and risk management liabilities.

(a) Fair value of financial instruments

The 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 balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

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

		December 31, 2016		December 31, 2015	
	Measurement Level	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets					
Financial assets at fair value through profit or loss:					
Risk management assets	2	$ –	$ –	$ 10,548	$ 10,548
Financial liabilities					
Financial liabilities at fair value through profit or loss:					
Risk management liabilities	2	$ 5,959	$ 5,959	$ 1,223	$ 1,223

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

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

(b) Risks associated with financial instruments

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

(i) Credit Risk

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

As at December 31, 2016, the Company held $5.4 million (2015 – $2.3 million) in cash at various major financial institutions throughout Canada and the USA; however, one Canadian financial institution held over 94% (2015 – 82%) of our cash and short-term deposits. The financial institution is a Canadian provincial crown corporation with a high investment grade rating and therefore we believe the credit risk is limited.

At December 31, 2016, 99% of receivables were from oil and gas marketers related to the sale of our oil and gas production. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate the credit risk associated with these marketers by assessing their financial strength and entering into relationships with larger purchasers with established credit history. During 2016 and 2015, the Company did not experience any collection issues with its marketers.

In 2016, the Company had four customers (2015 – four) which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these collective customers represented approximately 87% (2015 – 80%) of the Company's total oil and gas sales in 2016.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2016 and 2015, the Company did not experience any collection issues with risk management contracts.

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

(ii) Liquidity risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company has an on-going cash flow planning and forecasting model to help determine the funds required to meet its operational needs at all times. In addition, the Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at December 31, 2016, the Company had $117.5 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

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
2016			
Accounts payable and accrued liabilities	17,950	–	–
Risk management liabilities	2,826	2,681	452
2015			
Accounts payable and accrued liabilities	13,939	–	–
Risk management liabilities	–	–	1,223
Long-term debt (1)	1,672	1,672	89,393

(1) Includes principal and interest. Interest is based on rates existing at December 31, 2015.

(iii) Interest Rate Risk

Interest rate risk refers to the risk that a financial instrument, or cash flows associated with the instrument, will fluctuate due to changes in market interest rates. The Company is exposed to interest rate risk related to interest expense on its credit facilities due to the floating interest rate charged on advances. For the year ended December 31, 2016, if interest rates had been one percent higher with all other variables held constant, after tax net loss for the year would have been approximately $788,000 higher (2015 – $207,000 higher). In addition, the Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2016, if interest rates had been 1 percent higher with all other variables held constant, after tax net loss for the year ended December 31, 2016 would have been approximately $40,000 lower (2015 – $55,000 lower). The Company has not entered into any fixed rate contracts to mitigate its interest rate risk.

(iv) Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in foreign currency exchange rates and the volatility of those rates. This exposure primarily relates to: (i) revenues received for the sale of its crude oil production are primarily priced in US dollars while most of the Company's operating and capital expenditures are denominated in Canadian dollars and (ii) certain deposits and accounts payable are denominated in US dollars. As at December 31, 2016, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at December 31, 2016, the Company held US $0.4 million (2015 – US $0.9 million) in cash and cash equivalents. 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 year would have been approximately $37,000 higher (2015 – $62,000 higher) as a result of the re-valuation of the Company's US dollar denominated financial assets and liabilities as at December 31, 2016. 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 2% (2015 – 5%) of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current revenues.

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

Risk management amounts recognized were as follows:

	Year ended December 31, 2016	Year Ended December 31, 2015
Realized gain on risk management contracts	$ 10,793	$ 37,227
Unrealized loss on risk management contracts	(15,283)	(11,303)
Gain (loss) on risk management contracts	$ (4,490)	$ 25,924

The table below summarizes the Company's outstanding commodity contracts as at December 31, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type	Fair value
2017						
Oil	500 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 52.75/bbl	Swap	$ (205)
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 50.00/bbl	Swap	(1,409)
Oil	1,000 bbls/d	January 1 to December 31	CDN$ WCS	CDN$ 49.50/bbl	Swap	(1,687)
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 52.50/bbl	Collar	(320)
Oil	500 bbls/d	January 1 to June 30	CDN$ WCS	CDN$ 40.00/bbl to 47.00/bbl	Collar	(631)
Oil	1,000 bbls/d	January 1 to December 31	US$ WTI	US$ 60.00/bbl	Sold Call	(1,255)
2018						
Oil	500 bbls/d	January 1 to December 31	US$ WTI	US$ 70.00/bbl	Sold Call	(452)
Total						$ (5,959)
Current portion of fair value of contracts						$ (5,507)
Non-current portion of fair value of contracts						$ (452)

As at December 31, 2016, a 10% decrease to the oil price used to calculate the fair value for the risk management contracts would result in an approximate $7.5 million increase in fair value of these contracts and decrease in the after tax net loss for the year.

The table below summarizes commodity contracts the Company entered into subsequent to December 31, 2016:

Subject of Contract	Volume	Term	Reference	Strike Price	Type
2017					
Oil	500 bbls/d	February 1 to December 31	CDN$ WCS	CDN$ 54.30/bbl	Swap
Oil	500 bbls/d	February 1 to December 31	US$ WCS	US$ 40.15/bbl	Swap

(c) Capital Management

The Company's objective when managing capital is to safeguard our ability to continue as a going concern in order to pursue the development of our oil and gas properties and to maintain a capital structure that optimizes the cost of capital at an acceptable risk. The Company's capital structure consists of working capital, long-term debt and shareholders' equity. Additional funding will likely be required to continue to develop some of the Company's thermal assets as the existing credit facilities and cash flows from operating activities will not be sufficient to fully fund their development given the relatively large capital expenditures required to bring the assets into production. The Company will evaluate funding options for these projects, which includes acquiring additional debt financing, further equity offerings, entering into joint venture agreements and/or using proceeds from the disposition of properties.

In order to maintain or adjust its capital structure, the Company may from time to time issue additional common shares. In addition, the Company's credit facilities are based, in part, on its petroleum and natural gas reserves whose values are impacted by, among other things, global commodity prices. The Company will adjust its capital spending if access to external capital sources is unavailable. In order to manage the balance in the Company's capital structure, some of the financial tests that BlackPearl considers are debt-to-equity ratios, debt-to-cash-flow from operating activities and interest coverage tests, which is calculated as earnings before interest, taxes, depletion, depreciation and amortization (EBITDA) over interest expense. At December 31, 2016, the Company had a debt to EBITDA ratio of zero (2015 – 1.75). We target to maintain a debt to EBITDA ratio of less than 1.5; however, during the construction phase of our large assets and before production commences or during a period of low commodity prices, this will likely be exceeded. To facilitate the management and control of these ratios, the Company prepares annual operating and capital budgets. These budgets are generally updated quarterly or more frequently if circumstances change.

The Company's current policy is to not pay dividends but rather to reinvest its earnings back into the business.

18. SUPPLEMENTARY INFORMATION

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

	Year ended December 31, 2016	Year Ended December 31, 2015
Cash interest paid	$ 3,262	$ 3,498

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

	Year ended December 31, 2016	Year Ended December 31, 2015
Gross interest and financing charges	$ 3,262	$ 3,498
Capitalized interest and financing charges	–	(2,066)
Net interest and financing charges	3,262	1,432
Accretion of decommissioning liabilities	1,461	1,646
Finance costs	$ 4,723	$ 3,078

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

	Year ended December 31, 2016	Year Ended December 31, 2015
Changes in non-cash working capital		
Trade and other receivables	$ (2,590)	$ 7,666
Inventory	559	33
Prepaid expenses and deposits	578	(283)
Accounts payable and accrued liabilities	3,965	(46,954)
Changes in non-cash working capital	$ 2,512	$ (39,538)
Relating to:		
Operating activities	$ (1,704)	$ 13,913
Investing activities	$ 4,216	$ (53,451)