

CALGARY, ALBERTA--(Marketwired - Feb. 23, 2017) - [BlackPearl Resources Inc.](#) ("we", "our", "us", "BlackPearl" or the "Company") (TSX:PXX)(OMX: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 (Mbbbl)	Bitumen (Mbbbl)	Natural Gas (MMcf)	2016 Total (MBoe)	2015 Total (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) BOEs 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 (Mbbbl)	Bitumen (Mbbbl)	Natural Gas (MMcf)	BOE (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 (US\$/bbl)	Canadian Light Sweet Crude 40° API (CDN\$/bbl)	Western Canadian Select 20.5° API (CDN\$/bbl)	Alberta AECO-C Spot (CDN\$/MMBtu)	Inflation rate (%/yr)	Exchange rate (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:

- "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.
- "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.
- "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.
- "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.
- "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.
- "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.
- 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⁾

Project	Maturity Subclass ⁽³⁾	Chance of Development ⁽⁴⁾	Risked Volumes ⁽⁴⁾				Unrisked Volumes			
			Heavy Crude Oil		Bitumen		Heavy Crude Oil		Bitumen	
			Gross ⁽⁵⁾	Net	Gross ⁽⁵⁾	Net	Gross ⁽⁵⁾	Net	Gross ⁽⁵⁾	Net
			(Mbbbl)		(Mbbbl)		(Mbbbl)		(Mbbbl)	
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

Project	Net Present Values of Future Net Revenue Before Income Taxes				
	Discounted at (%/year)				
	0%	5%	10%	15%	20%
	(\$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 quantities 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 not 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 the 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 unrisks contingent resources have been adjusted for risk based on the chance of development (risk amounts represent unrisks 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 (unrisks 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 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 agreement 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 (unrisks 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 drilling 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 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.

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.

Contact

[BlackPearl Resources Inc.](#)

John Festival
President and Chief Executive Officer
(403) 215-8313

[BlackPearl Resources Inc.](#)

Don Cook
Chief Financial Officer
(403) 215-8313
www.blackpearlresources.ca

Robert Eriksson
Investor Relations Sweden
+46 8 545 015 50