CALGARY, ALBERTA--(Marketwired - Feb. 25, 2016) - 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, 2015 as well as the results of its 2015 year-end oil and gas reserves and resources evaluations.

Highlights and accomplishments included:

- Q4 2015 oil and gas production was 9,521 boe/day, a 27% increase from the third quarter. The increase reflects the successful production start-up of our Onion Lake thermal project. For the full year, production averaged 8,330 boe/day in 2015.
- We achieved positive results from our cost reduction strategy in 2015. Operating costs, on a boe basis, were 21% lower in 2015 compared to 2014.
- Q4 2015 revenue was $23 million and funds flow from operations (a non-GAAP measure) was $11 million, down from Q4 2014 as a result of lower oil prices. For the year, oil and gas revenue was $96 million and funds flow from operations was $49 million.
- Capital expenditures in 2015 were $69 million, a decrease from $235 million in 2014. Capital expenditures were reduced in 2015 due to completion of the Onion Lake thermal facilities in the first half of the year and our desire to maintain financial flexibility in this challenging oil price environment.
- At Onion Lake, we completed construction of phase one of the Onion Lake thermal project in the spring and we commenced commercial production at the beginning of the fourth quarter this year. The project is currently producing approximately 4,500 barrels of oil per day and we are continuing to optimize the project and expect to reach design production capacity of 6,000 barrels of oil per day by mid-2016. The project was completed on time and on budget, with capital costs of approximately $225 million.
- At Blackrod, we continue to achieve positive results from the SAGD pilot. In Q4, the second well pair produced an average of 562 bbls/day and for the full year the well produced 500 bbls/day with an average steam oil ratio of 2.75. Cumulatively, the well has produced in excess of 280,000 barrels of oil. These successful results strengthens our confidence that we have the technical information to move towards commercial development. The regulatory review for our 80,000 bbls/day commercial development application, which was filed in 2012, is on-going.
- At Mooney, no new activities were initiated in 2015 as our primary focus was to achieve operating cost savings in the field. Field operating costs decreased over 40% in 2015 compared to 2014.
- Sproule Unconventional Limited ("Sproule"), our independent reserves evaluator, assigned proved plus probable reserves of 294 million barrels of oil equivalent to our properties in their 2015 year-end evaluation. Proved developed producing reserves increased 127% as a result of the reclassification of the reserves assigned to the first phase of the Onion Lake thermal project from undeveloped to producing.
- Risked contingent resources (best estimate) for our three core properties totaled 494 million barrels of oil equivalent.

John Festival, President of BlackPearl, commenting on activities indicated that "although 2015 was a challenging year for the oil and gas sector we still made significant progress in the development of our properties. This included successfully building, commissioning and commencing production of our first commercial thermal project at Onion Lake. Additionally, in 2015, we continued to receive positive results from our SAGD pilot at Blackrod; results that will set us up for commercial development of this large resource when economic conditions permit. We are managing in this low price environment by reducing our costs and limiting capital expenditures to maintain a strong financial position."

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2015	2014	2015	2014
Daily sales volumes				
Oil (bbls/d)	8,785	8,567	7,434	8,492
Bitumen (bbls/d) (1)	562	523	541	380
Combined (bbls/d)	9,347	9,090	7,975	8,872
Natural gas (mcf/d)	1,047	3,294	2,130	2,492
Combined (boe/d) (2)	9,521	9,639	8,330	9,287
Product pricing ($)				
Crude oil - per bbl	27.65	59.34	35.00	72.47
Natural gas - per mcf	2.91	3.39	2.72	4.12
Combined - per boe (2)	27.45	57.00	34.14	70.24

Realized gains on risk management contracts - per boe	12.54	6.97	13.20	0.58
($000s, except where noted)				
Oil and natural gas revenue - gross	22,630	47,798	96,271	228,345
Net income (loss) for the period	(31,172)	16,254	(46,793)	26,825
Per share, basic ($)	(0.09)	0.05	(0.14)	0.08
Per share, diluted ($)	(0.09)	0.05	(0.14)	0.08
Funds flow from operations [3]	10,898	19,716	48,962	89,723
Capital expenditures	1,665	57,700	68,508	235,366
Working capital deficiency (surplus), end of period	(11,063)	18,237	(11,063)	18,237
Long term debt	88,000	29,000	88,000	29,000
Net Debt [4]	76,937	47,237	76,937	47,237
Shares outstanding, end of period (000s)	335,638	335,638	335,638	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) *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 uses this non-GAAP measurement for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.*

(4) *Net debt is a non-GAAP measure.*

FOURTH QUARTER 2015 ACTIVITIES

Activities in the fourth quarter of 2015 continued to be impacted by lower oil prices. Oil and gas revenues were $22.6 million in the fourth quarter of 2015, 53% lower compared to the same quarter of 2014. The decrease in revenues is primarily attributable to a decrease in our average realized crude oil sales price in Q4 2015. WTI oil prices averaged US$42.18 per barrel in Q4 2015 compared to US$73.15 per barrel in Q4 2014. Lower 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 $27.65 per barrel in the fourth quarter of 2015 compared with $59.34 per barrel in the fourth quarter of 2014.

BlackPearl sold an average of 9,521 boe/day during the fourth quarter of 2015 compared with 9,639 boe/day during the fourth quarter of 2014. Production in the fourth quarter of 2015 increased significantly from the first three quarters of the year (7,930 boe/day) as a result of first commercial production from our Onion Lake thermal project. During the fourth quarter the thermal project produced 3,010 barrels of oil per day.

Production costs were $14.6 million or $17.77 per boe in the fourth quarter of 2015 compared to $21.1million or $25.12 per boe in the fourth quarter of 2014. The decrease in production costs in 2015 is primarily due to on-going field optimization efforts in a low price environment, which included reduced well maintenance work, shutting in some of our high cost production, not re-starting wells that required servicing and lower chemical costs related to our ASP flood at Mooney. General and administrative expenses were $1.8 million in the fourth quarter of 2015 compared to $1.9 million in the fourth quarter of 2014.

Funds flow from operations in the fourth quarter of 2015 was $10.9 million compared to $19.7 million in the fourth quarter of 2014. The decrease reflects lower revenues in Q4 2015. Net loss in the fourth quarter of 2015 was $31.2 million compared to net income of $16.3 million in the fourth quarter of 2014. The net loss in Q4 2015 included a non-cash impairment write-down of $33.0 million related to our Mooney area assets. The write-down is attributable to the current low oil price environment. The net loss in Q4 2015 also includes realized gains on risk management contracts (oil price hedging contracts) of $10.3 million.

Capital expenditures were limited in the fourth quarter of 2015 due to low oil prices. Capital spending was $1.7 million during the quarter compared with $57.7 million in Q4 2014.

Production

BlackPearl's Q4 2015 oil and gas sales volumes were 9,521 boe per day, a 27% increase over production during the third quarter. The increase in fourth quarter production is attributable to initial production from the star-up of our Onion Lake thermal project.

	Three months ended December 31,		Twelve months ended December 31,	
Production by Area (boe/d)	2015	2014	2015	2014
Onion Lake - conventional	2,914	4,651	3,312	4,263
Onion Lake - thermal	3,010	-	951	-
Mooney	1,902	3,236	2,367	3,469
John Lake	955	1,109	989	1,067
Blackrod SAGD Pilot	562	523	541	380
Other	178	120	170	108
Total production	9,521	9,639	8,330	9,287

Operating Netback

	Three months ended December 31,		Twelve months ended December 31,	
($/boe)	2015	2014	2015	2014
Oil and natural gas revenue	27.45	57.00	34.14	70.24
Realized gains on risk management contracts	12.54	6.97	13.20	0.58
	39.99	63.97	47.34	70.82
Royalties	4.35	11.51	5.70	13.49
Transportation costs	1.23	1.48	1.13	1.89
Production costs	17.77	25.12	19.94	25.24
Operating netback(1)	16.64	25.86	20.57	30.20

(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
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WCS(1)	CDN$ 51.15/bbl	Swap
Oil	2,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WCS(1)	CDN$ 47.60/bbl	Swap
Oil	2,000 bbls/d	January 1, 2016 to December 31, 2016	US$ WTI(2)	US$ 65.00/bbl	Sold Call
Oil	1,000 bbls/d	January 1, 2017 to December 31, 2017	US$ WTI(2)	US$ 60.00/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

2016 Outlook - February Update

Our initial guidance for 2016 was released in December 2015 and as a result of the continued decrease in crude oil prices, we have updated our 2016 guidance. Our focus for the year will continue to be maintaining a strong balance sheet by limiting our capital spending until we see signs of a sustained price recovery. In 2016, we are planning to spend $10 to $15 million on capital projects down from our initial guidance which was to spend between $15 and $20 million. Budgeted capital spending includes preliminary planning for the second 6,000 bbl/d phase at the Onion Lake thermal EOR project, continuing to operate the Blackrod SAGD pilot throughout the year and maintenance capital in all our core areas. Expansion of the Mooney ASP flood has been deferred until oil prices improve. The Company continues to have the flexibility to expand or defer our capital program as economic conditions change.

The capital program is expected to be funded from our anticipated funds flow from operations and supplemented, if necessary, with our existing credit facilities. Funds flow from operations was initially budgeted to be between $35 and $40 million, but as a result of lower crude oil prices, we have updated our funds flow from operations to be between $5 and $10 million. This decrease in funds flow from operations resulted in our updated year end debt levels to be between $90 and $95 million, an increase from our initial guidance of $70 to $75 million. The updated guidance is based on a WTI oil price of US$35/bbl, a heavy oil differential of US$14/bbl and a Cdn/US dollar exchange rate of 0.71.

Our initial guidance for 2016 production was to average between 10,000 and 10,500 bbls/d. Due to the continued decrease in crude oil prices, the Company has decided to temporarily shut-in approximately 75% of the production from the first phase of the Mooney ASP flood (approximately 1,000 bbls/day) and defer the expansion of the Mooney ASP flood until oil prices improve. As a result, we have updated our 2016 production guidance to average between 9,000 and 10,000 bbls/d. We will continue to monitor crude oil prices and make changes to our capital spending programs and operations as we believe are required. This may include shutting-in some of our higher operating cost wells until oil prices improve.

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, 2015. 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	2015 Total	2014 Total
	(Mbbl)	(Mbbl)	(MMcf)	(MBoe)	(MBoe)
Proved developed producing	19,859	0	291	19,907	8,766
Proved developed non-producing	2,652	0	126	2,673	2,114
Proved undeveloped	40,935	429	71	41,376	55,275
Total proved	63,446	429	487	63,956	66,165
Probable	50,612	179,338	363	230,010	230,456
Total proved plus probable	114,058	179,767	850	293,966	296,621

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	563,561	468,219	393,887	336,878	292,798
Developed non-producing	62,301	47,527	36,832	28,956	23,061
Undeveloped	1,341,432	687,208	388,170	238,426	156,510
Total proved	1,967,294	1,202,954	818,889	604,260	472,369
Probable	6,449,560	2,843,921	1,396,392	736,310	403,222
Total proved plus probable	8,416,854	4,046,875	2,215,281	1,340,569	875,591
After Tax					
Proved					
Developed producing	563,561	468,219	393,887	336,878	292,798
Developed non-producing	62,301	47,527	36,832	28,956	23,061
Undeveloped	992,882	511,591	291,152	180,650	119,979
Total proved	1,618,744	1,027,336	721,871	546,484	435,838
Probable	4,676,236	2,030,874	969,327	488,295	248,237
Total proved plus probable	6,294,980	3,058,210	1,691,198	1,034,779	684,075

Notes:

(1) Based on Sproule's December 31, 2015 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 the proved, and proved plus probable reserves on production.

($ Millions)	Total Proved	Total Proved + Probable
2016	7.5	5.0
2017	31.6	118.6
2018	30.0	139.2
2019	28.2	95.8
2020	26.0	336.4
Remainder	268.8	1,660.6
Total FDC undiscounted	392.1	2,355.6
Total FDC discounted at 10%	180.5	1,018.2

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, 2014 to December 31, 2015.

	Heavy Crude Oil (Mbbl)	Bitumen (Mbbl)	Natural Gas (MMcf)	BOE (MBOE)
Proved				
Balance, Dec 31, 2014	64,358	1,739	407	66,165
Extensions	44	0	0	44
Technical revisions	2,182	0	975	2,344
Economic factors	(425)	(1,112)	(109)	(1,555)
Production	(2,712)	(198)	(786)	(3,041)
Balance, Dec 31, 2015	63,446	429	487	63,956
Probable				
Balance, Dec 31, 2014	50,947	179,456	319	230,456
Extensions	99	0	0	99
Technical revisions	(608)	0	83	(594)
Economic factors	174	(119)	(39)	49
Production	0	0	0	0
Balance, Dec 31, 2015	50,612	179,338	363	230,010
Proved plus Probable				
Balance, Dec 31, 2014	115,305	181,195	726	296,621
Extensions	143	0	0	143
Technical revisions	1,574	0	1,058	1,750
Economic factors	(251)	(1,231)	(148)	(1,507)
Production	(2,712)	(198)	(786)	(3,041)
Balance, Dec 31, 2015	114,058	179,767	850	293,966

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$/Cdn$)
2016	45.00	55.20	45.26	2.25	0.0	0.75
2017	60.00	69.00	57.96	2.95	0.0	0.80
2018	70.00	78.43	65.88	3.42	1.5	0.83
2019	80.00	89.41	75.11	3.91	1.5	0.85
2020	81.20	91.71	77.03	4.20	1.5	0.85
2021	82.42	93.08	78.19	4.28	1.5	0.85
2022	83.65	94.48	79.36	4.35	1.5	0.85
2023	84.91	95.90	80.55	4.43	1.5	0.85

2024 86.18	97.34	81.76	4.51	1.5	0.85
2025 87.48	98.80	82.99	4.59	1.5	0.85
2026 88.79	100.28	84.23	4.67	1.5	0.85

Escalation rate of 1.5% 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:

1. "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.
2. "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.
3. "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.
4. "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.
5. "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.
6. "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.
7. 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, 2015. The reports were independently prepared in accordance with definitions, standards and procedures contained in the COGE Handbook.

Amendments to NI 51-101 came into effect on July 1, 2015 and these amendments resulted in significant changes to the way contingent resources are disclosed compared to prior years. The most significant changes include:

- Changes to the product types, including the addition of new product types and providing new definitions for some existing product types;
- The classification of contingent resources into the following project maturity subclasses: Development pending, Development on hold, Development unclarified, and Development not viable;
- Disclosure of the chance of development risk for each project maturity subclass;
- The requirement to risk the contingent resource amounts based on the chance of development and disclose the risked, best estimate contingent resources for each product type;
- For any contingent resources classified as "Development pending", the disclosure of the risked NPV of future net revenues, calculated using forecast prices and costs for each product type using discount rates of 0%, 5%, 10%, 15% and 20%;
- For any contingent resources reported in the subclass "Development on hold", the disclosure of and/or a comment on the economic viability of the contingent resources;
- The disclosure of the estimated total cost to achieve commercial production, the estimated date of first commercial production and the recovery technology to be used; and
- The disclosure and a discussion of the contingencies that need to be overcome in order to convert the contingent resources to reserves.

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] Heavy Crude Oil Gross[5] (Mbbl)	Net	Bitumen Gross[5] (Mbbl)	Net	Unrisked Volumes Heavy Crude Oil Gross[5] (Mbbl)	Net	Bitumen Gross[5] (Mbbl)	Net
Blackrod[6]	Development/ pending	80%			452,908	358,722			566,135	448,402
Onion Lake[7]	Development/ pending	90%	29,889	23,362			33,210	25,958		
Mooney[8]	Development/ on hold	71%	11,162	8,875			15,721	12,500		

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% ($M)	5%	10%	15%	20%
Risked Volumes[4]					
Blackrod	10,805,213	3,300,966	1,071,569	330,343	65,200
Onion Lake	1,087,542	460,899	218,983	114,131	63,520
Mooney	305,484	152,083	79,431	42,886	23,601
Unrisked Volumes					
Blackrod	13,506,517	4,126,208	1,339,461	412,929	81,500
Onion Lake	1,208,380	512,111	243,315	126,812	70,578
Mooney	430,259	214,201	111,874	60,402	33,241

Project	Net Present Values of Future Net Revenue After Income Taxes[10] Discounted at (%/year) 0% ($M)	5%	10%	15%	20%
Risked Volumes[4]					
Blackrod	7,815,272	2,304,132	685,097	161,012	-16,369
Onion Lake	789,321	330,535	153,761	77,504	40,976
Mooney	222,401	109,114	55,736	29,127	15,263
Unrisked Volumes					
Blackrod	9,769,090	2,880,165	856,371	201,265	-20,462
Onion Lake	877,023	367,261	170,845	86,115	45,529
Mooney	313,240	153,682	78,502	41,024	21,497

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 economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Conting 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 classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quan that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the be estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will or exceed the best estimate.

(3) Contingent resources are further classified based on project maturity. The project maturity subclasses include development pen development on hold, development unclarified and development not viable. All of the Company's contingent resources are class 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 contingen 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 conti resources have been adjusted for risk based on the chance of development (risked amounts represent unrisked values multiplie the Chance of Development).

(5) "Gross" means the Company's working interest share in the contingent resources of bitumen and heavy oil before deducting roy 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 proce 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 m evaluation drilling, as required by the regulatory process, to define the reservoir characteristics to assist in the implementation a 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 endorse from the Board of Directors of the Company to move forward with commercial development; 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 estim timing of first commercial production is 2024 and the estimated capital to reach first commercial production is $1.3 billion (risked escalated for inflation).

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

• For phase 3 of the Onion Lake thermal EOR project, the contingencies in the Sproule Report associated with the Compar Onion Lake contingent resources are due to the following: (a) the requirement for more evaluation drilling to define the res characteristics; and (b) the absence of an application by the Company to expand the facility capacities and to extend the development area beyond phase 1, additionally, the current agreements with the Onion Lake Cree Nation (OLCN) are sul policies and approvals by Indian Oil and Gas Canada (IOGC) and there is a potential for these agreements to be renegoti due to changes imposed by IOGC. For the Onion Lake thermal EOR project contingent resources, the estimated timing o commercial production is 2020, while the estimated capital to reach first commercial production is $61.0 million (risked an escalated for inflation).

• For the extension of the primary development area, the contingencies in the Sproule Report associated with the Company 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 curren 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 prima development area has already been achieved and, as a result, estimated capital to reach first commercial production is ni

(8) The established recovery technology to be used for phases 3 and 4 of the Mooney project is the established ASP flood process 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 w 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 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 th Mooney ASP flood has already been achieved and, as a result, estimated capital to reach first commercial production at the Mo 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 res 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-alon 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 & a 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, 2015 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 5, 2016 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 volumes and net present values of

BlackPearl's proved and probable reserves and contingent resources, the estimated 6,000 barrel per day productive capacity of the Onion Lake thermal project as well as the mid-2016 target date to reach that productive capacity and all the information under *2016 Outlook - February Update*.

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

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

"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.

"Net debt" is a non-GAAP measure that represents long term debt less working capital.

The information in this release is subject to the disclosure requirements of BlackPearl Resources Inc. under the Swedish Securities Market Act and/or the Swedish Financial Instruments Trading Act. This information was publicly communicated on February 25, 2016 at 3:00 p.m. Mountain Time.

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