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NEWS RELEASE **February 26, 2015**

BLACKPEARL ANNOUNCES FOURTH QUARTER AND FULL YEAR 2014 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA – BlackPearl Resources Inc. ("we", "our", "us", "BlackPearl" or the "Company") (TSX: PXX) (NASDAQ OMX Stockholm: PXXS) is pleased to announce its financial and operating results for the three and twelve months ended December 31, 2014.

Highlights and accomplishments in 2014 included:

- Q4 2014 oil and gas production was 9,639 boe/day and oil and gas production for the year was 9,287 boe/day;

- Q4 2014 revenue was $48 million and funds flow from operations (a non-GAAP measure) in the fourth quarter was $20 million. For the year, oil and gas revenue was $228 million and funds flow from operations was $90 million;

- Q4 2014 net income was $16.3 million compared to $0.2 million in Q4 2013. Net income for the year increased to $26.8 million in 2014 compared with net income of $6.4 million in 2013;

- Capital expenditures in 2014 were $235.4 million, up from $93.5 million in 2013;

- As reported on January 29, 2015, Sproule Unconventional Limited ("Sproule"), our independent reserves evaluator, increased BlackPearl's year-end 2014 oil and gas proved plus probable reserves to 296 million barrels of oil equivalent, before royalties. Contingent resources (best estimate) for our three core properties totaled 616 million barrels of oil equivalent, before royalties;

- At Onion Lake, we focused our 2014 capital spending program on the construction of the first phase of our thermal project. This phase of the project is designed for productive capacity of 6,000 bbls/day. In addition to steam, water and oil handling facilities, this phase of the project includes 13 horizontal production wells and up to 35 vertical injection wells. All of these wells were drilled by the end of the year and are currently being completed. All of the modules of the central processing facilities have been delivered and are being assembled on site. Construction is approximately 80% complete and we are on target to commence steam injection by mid-2015. We expect capital costs will be in line with our budget of $220 million. In addition to thermal development at Onion Lake we continued with our primary development program, drilling 20 successful wells in 2014;

- At Blackrod, we continued to achieve positive results from our SAGD pilot in 2014. The second well pair reached oil production rates of 400 bbls/day during the fourth quarter with a steam oil ratio of near 3, and the well is still in its ramp-up phase. Cumulatively, the well has produced in excess of 80,000 barrels of oil. The regulatory approval process for our 80,000 bbls/day commercial development application has been an extensive process. We have successfully responded to all of the regulators supplemental requests for information and we have addressed all statements of concern raised by area stakeholders. We expect formal approval of the project later this spring;

- At Mooney, in 2014 we completed drilling on phase two lands in preparation for the expansion of our alkali, surfactant, polymer (ASP) flood to these areas. Due to low oil prices we have elected to defer this expansion until 2016. We also commenced development drilling on phase 3 lands at Mooney, drilling five wells. We anticipate expanding the ASP flood to these lands in the future. The Alberta government implemented a new royalty structure in 2014 for EOR projects, which includes our ASP flood at Mooney. Generally, the new royalty structure is positive for new projects, such as our Mooney ASP flood, during their initial years of production.

John Festival, President of BlackPearl, commenting on activities indicated that "we achieved strong production and cash flow performance during the fourth quarter of 2014. Unfortunately this has been overshadowed by global events in the oil and gas sector as the industry is currently facing a very challenging pricing environment. We have responded by scaling back much of our capital spending until prices improve. However, we are continuing to move forward with our Onion Lake thermal project. Production from our thermal project is expected to be our most economic production in terms of operating netbacks, which is critically important in a low price environment. The Onion Lake project is on schedule and on budget and we are planning to start commissioning the facilities during the second quarter of 2015.

We will continue to monitor the volatility in oil prices and will adjust our plans as required, which may include altering our spending programs as well as shutting-in some of our higher cost production until we see sustained improvement in prices. We are also working closely with our service providers, as well as conducting internal assessments to achieve cost savings wherever possible. We have an exciting inventory of projects and as oil prices recover we will look to aggressively develop these projects to expand our asset and production base."

Financial and Operating Highlights

	Three months ended December 31,		Twelve months ended December 31,	
	2014	2013	2014	2013
Daily sales volumes [1]				
Oil (bbls/d) [2]	8,567	9,981	8,492	9,255
Bitumen (bbls/d)	523	262	380	236
	9,090	10,243	8,872	9,491
Natural gas (mcf/d)	3,294	1,266	2,492	1,434
Combined (boe/d)	9,639	10,454	9,287	9,730
Product pricing ($)				
Crude oil - per bbl	59.34	58.44	72.47	65.09
Natural gas - per mcf	3.39	3.50	4.12	3.16
Combined - per boe	57.00	57.67	70.24	64.11
($000s, except where noted)				
Oil and natural gas revenue – gross	47,798	54,072	228,345	222,157
Net income for the period	16,254	226	26,825	6,449
Per share, basic ($)	0.05	0.00	0.08	0.02
Per share, diluted ($)	0.05	0.00	0.08	0.02
Funds flow from operations [3]	19,716	20,735	89,723	86,206
Capital expenditures	57,700	22,749	235,366	93,491
Property dispositions	-	(2,032)	-	(2,032)
Working capital, end of period	(18,237)	(8,782)	(18,237)	(8,782)
Long term debt	29,000	-	29,000	-
Shares outstanding, end of period (000s)	335,638	300,425	335,638	300,425

(1) *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.*
(2) *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.*
(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.*

FOURTH QUARTER 2014 ACTIVITIES

Oil and gas revenues were $47.8 million in the fourth quarter of 2014 compared to $54.1 million in the same quarter of 2013. The decrease in revenues is attributable to an 11% decrease in oil and gas production partially offset by a 2% increase in realized average crude oil sales prices.

BlackPearl sold an average of 9,639 boe/day during the fourth quarter of 2014 compared with 10,454 boe/day during the fourth quarter of 2013. The decrease in sales volumes was mostly attributable to natural production declines at Onion Lake and from the phase two lands at Mooney. In addition, production was lower in 2014 as a result of changing the focus of our 2014 capital spending program from short-term production growth activities to the construction of the first phase of the Onion Lake thermal project. Over 75% of our 2014 capital spending was dedicated to the construction of the Onion Lake thermal project.

Tighter heavy oil differentials and a weaker Canadian dollar relative to the US dollar contributed to a slight increase in our realized crude oil sales price in the fourth quarter of 2014 compared with the fourth quarter of 2013. In Q4 2014 WTI prices averaged US$73.15 per barrel (Q4 2013 – US$97.46), heavy oil differentials were US$14.39 per barrel (Q4 2013 – US$ 32.21) and the Canadian dollar was $0.88 relative to the US dollar (Q4 2013 - $0.95). This resulted in our wellhead price averaging $59.34 per barrel in the fourth quarter of 2014 compared with $58.44 per barrel in the fourth quarter of 2013.

Production costs were $21.1 million or $25.12 per boe in the fourth quarter of 2014 compared to $18.4 million, and $19.65 per boe in the fourth quarter of 2013. The increase in production costs is primarily due to the expensing of all costs associated with the first phase of the ASP flood at Mooney. In prior years these costs were being capitalized during the initial re-pressurization of the reservoir. G&A expenses were $1.9 million in the fourth quarter of 2014 compared to $2.1 million in the fourth quarter of 2013.

Funds flow from operations in the fourth quarter of 2014 was $19.7 million compared to $20.7 million in the fourth quarter of 2013. The decrease reflects lower revenues in Q4 2014. Net income in the fourth quarter of 2014 was $16.2 million compared to a $0.2 million in the fourth quarter of 2013. Net income in Q4 2014 included $20.7 million in unrealized gains on risk management contracts (oil price hedging contracts) the Company had previously entered into. Unrealized gains on these contracts represent the non-cash change in the mark-to-market values of our outstanding risk management contracts.

Capital expenditures in the fourth quarter of 2014 were $57.7 million, a 154% increase compared to the fourth quarter of 2013. The majority of expenditures in Q4 2014 related to the on-going construction of the Onion Lake thermal project.

Production

BlackPearl's Q4 2014 oil and gas sales volumes were 9,639 boe per day, a 4% increase over production during the third quarter. The increase in fourth quarter production is mainly attributable to additional primary development drilling at Onion Lake. At Onion Lake, we drilled 11 conventional wells during the third quarter of 2014 which began to contribute to production in the fourth quarter.

	Three months ended December 31,		Twelve months ended December 31,	
Production by Area (boe/d)	2014	2013	2014	2013
Onion Lake	4,651	5,186	4,263	4,797
Mooney	3,236	3,837	3,469	3,685
John Lake	1,109	1,066	1,067	898
Blackrod SAGD Pilot	523	262	380	236
Other	120	103	108	114
	9,639	10,454	9,287	9,730

Operating Netback

	Three months ended December 31,		Twelve months ended December 31,	
($/boe)	2014	2013	2014	2013
Oil and natural gas revenue	57.00	57.67	70.24	64.11
Realized gains on risk management contracts	6.97	-	0.58	-
	63.97	57.67	70.82	64.11
Royalties	11.51	11.87	13.49	12.62
Transportation costs	1.48	1.77	1.89	2.77
Production costs	25.12	19.65	25.24	20.84
Operating netback[1]	25.86	24.38	30.20	27.88

(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	1,500 bbls/d	January 1, 2015 to March 31, 2015	CDN$ WCS[2]	CDN$ 80.20/bbl	Swap
Oil	2,500 bbls/d	January 1, 2015 to June 30, 2015	CDN$ WCS[2]	CDN$ 80.00/bbl	Swap
Oil	1,000 bbls/d	July 1, 2015 to December 31, 2015	CDN$ WCS[2]	CDN$ 64.45/bbl	Swap
Oil	1,000 bbls/d	January 1, 2016 to December 31, 2016	CDN$ WTI[3]	CDN$ 80.00/bbl	Call Swaption[1]

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect, on December 31, 2015, exercise the option to enter into the oil swap.
(2)WCS refers to Western Canadian Select, a heavy oil reference price in Alberta
(3)WTI refers to West Texas Intermediate, a light oil reference price in Cushing Oklahoma

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, 2014 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 and special meeting of shareholders will be held on May 7, 2015 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 of BlackPearl's proved and probable reserves, the estimated volumes of BlackPearl's contingent resources, the estimated 6,000 barrel per day productive capacity of the Onion Lake thermal project as well as the estimated capital costs of $220 million of the project, the mid-2015 target date for initial steam injection for the first phase of the Onion Lake thermal project, potential production levels for the Blackrod SAGD project and the expected timing for regulatory approval of our commercial development application, and the expected timing for expansion of the Mooney ASP flood.

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.

Cautionary Statement on Contingent Resources

This news release 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. In the case of the contingent resources assigned to BlackPearl's three core projects the contingencies include the requirement for more evaluation drilling to better define the resource, the absence of submission of commercial SAGD development applications (for future phases of development at Blackrod), the likelihood of attaining regulatory approvals for commercial SAGD development (for our Onion Lake SAGD project), further establishment of increased oil production response from the ASP flood at Mooney and the uncertainty of the timing of production and development. There is no certainty that it will be commercially viable to produce any of the contingent resources. .These volumes are the arithmetic sums of the Best Estimate Resources for Blackrod, Mooney and Onion Lake. 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. Please refer to our Annual Information Form for a more detailed discussion of our contingent resources.

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. Cash 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.

For further information, please contact:

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2014

MANAGEMENT'S DISCUSSION AND ANALYSIS, FINANCIAL STATEMENTS AND NOTES

FOR THE YEAR ENDED DECEMBER 31, 2014

BLACKPEARL RESOURCES INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis (MD&A) of the operating and financial results of BlackPearl Resources Inc. ("BlackPearl" or "the Company") for the year ended December 31, 2014. These results are being compared with the year ended December 31, 2013. The MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2014, 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		

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses terms "funds flow from operations", "funds flow from operations per share – basic", "funds flow from operations per share – diluted" and "operating netback". These terms do not have any standardized meaning as prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other issuers. These terms are used by the Company to analyze operating performance, leverage and liquidity and to provide shareholders and investors with additional information to measure the Company's performance and efficiency and its ability to fund a portion of its future activities and to service any long-term debt. Funds flow from operations is not intended to represent cash flow from operating activities or other measures of financial performance in accordance with GAAP. Operating netback is calculated as production sales less royalties, production costs and transportation costs, divided by total production for the period on a boe basis.

The following table reconciles non-GAAP measurement "Funds flow from operations" to "Cash flows from operating activities", the nearest GAAP measure. "Funds flow from operations" excludes decommissioning costs incurred and changes in non-cash working capital related to operations, while the GAAP measurement, "Cash flows from operating activities" includes these items. Funds flow from operations per share – basic & diluted is calculated as cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations divided by the average number of common shares outstanding for the period.

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Cash flows from operating activities [1]	**10,242**	23,772	**78,388**	80,698
Add (deduct):				
Decommissioning costs incurred	**263**	294	**963**	849
Changes in non-cash working capital related to operations	**9,211**	(3,331)	**10,372**	4,659
Funds flow from operations [2]	**19,716**	20,735	**89,723**	86,206

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

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

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

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

The effective date of this MD&A is February 25, 2015.

OVERVIEW

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

BlackPearl's current core properties are:

- Onion Lake, Saskatchewan – a conventional heavy oil property with a thermal EOR project under construction;
- Mooney, Alberta – a conventional heavy oil property using horizontal drilling and ASP flooding; and
- Blackrod, Alberta – a bitumen property located in the Athabasca oil sands region using the SAGD recovery process. The Company is currently operating a pilot project on this property.

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

2014 SIGNIFICANT EVENTS

- Capital expenditures during 2014 were $235.4 million, with approximately $183.9 million related to the construction of the Onion Lake thermal EOR project, $28.1 million spent at Mooney, $8.8 million spent at Onion Lake primary, $6.3 million spent at John Lake, $4.2 million spent at Blackrod and $4.1 million spent in other areas. The focus of the 2014 capital program was the commercial engineering design and construction of the Onion Lake EOR project and the drilling of 35 associated wells (production wells, steam injectors and service wells), the drilling of 20 conventional heavy oils wells at Onion Lake, seven horizontal wells at Mooney, six horizontal wells at John Lake and two horizontal wells at Reita Lake. In addition, 2014 capital spending included expansion of pipeline and road infrastructure at Mooney and the conversion of the second pilot well pair at Blackrod to the production test phase along with continued capitalization of net revenues from operating the Blackrod pilot.

- Oil and gas sales during 2014 were $228.3 million and funds flow from operations (non-GAAP measure) were $89.7 million. Net income was $26.8 million for the year ended December 31, 2014.

- During the first half of 2014 the Company issued 33,373,585 common shares at a price of $2.65 per share, for aggregate gross proceeds of $88.4 million. In addition, during 2014, 1,839,833 common shares were issued pursuant to the exercise of stock options which generated net proceeds of $2.0 million for the Company.

- The Company's Board of Directors approved development of the first phase of the Onion Lake EOR project. The first phase of development is being designed for production of approximately 6,000 bbls/d of oil; target date for completion of construction and first steam is mid-2015. Initial oil production from the project is expected within three months of steam injection and peak production rates are expected 12 to 15 months thereafter. At December 31, 2014, delivery of over 85% of the modules (98 of 115 units) for the central processing facilities had occurred and over 40% of the field construction was completed.

- The Company entered into a lump sum contract with Propak Systems Ltd. (Propak) for the engineering, procurement and fabrication of the central processing facilities for the Company's Onion Lake EOR project.

- During the second quarter of 2014 the Company's lending syndicate increased the Company's existing credit facilities from $115 million to $150 million. At December 31, 2014, BlackPearl had a working capital deficiency of $18.2 million and $29 million in long-term debt, leaving $121 million available to be drawn under the Company's existing credit facilities. The Company intends to use the net proceeds from the issuance of common shares and the increased credit facilities to fund ongoing capital expenditures, including the first phase of the Onion Lake EOR project and for general corporate purposes.

- BlackPearl increased its proved plus probable oil and gas reserves by 2% to 296 million boe, before royalties, as at December 31, 2014. 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 $2.7 billion.

- Sproule also attributed contingent resources (best estimate) of 616 million boe, before royalties, to the Company's working interest in its three core properties (see cautionary statement on contingent resources on page 29). The estimated pre-tax net present value of the future net cash flows of contingent resources (best estimate), discounted at 10% per annum was $2.0 billion.

ANNUAL FINANCIAL INFORMATION

($000s, except where noted)	**2014**	2013	2012
Total oil and gas sales	**228,345**	222,157	204,525
Net income	**26,825**	6,449	45
Per share – basic and diluted ($)	**0.08**	0.02	0.00
Funds flow from operations (1)	**89,723**	86,206	82,595
Per share – basic ($)	**0.27**	0.29	0.29
Per share – diluted ($)	**0.27**	0.29	0.28
Cash flow from operating activities (2)	**78,388**	80,698	79,862
Per share – basic ($)	**0.24**	0.27	0.28
Per share – diluted ($)	**0.24**	0.27	0.27
Capital expenditures	**235,366**	93,491	139,548
Total assets at year end	**837,773**	652,216	620,725
Common shares outstanding (000s)	**335,638**	300,425	295,766

(1) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

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

SELECTED QUARTERLY INFORMATION

	2014				2013			
($000s, except where noted)	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Production (boe/d) (1)	9,639	9,248	8,897	9,363	10,454	9,382	9,986	9,087
Oil and gas sales	47,798	58,818	62,174	59,555	54,072	69,092	58,322	40,671
Oil and gas sales ($/boe)	57.00	72.90	79.53	72.30	57.67	82.72	66.20	50.13
Production costs	21,066	21,021	20,291	19,673	18,420	16,664	18,413	18,702
Production costs ($/boe)	25.12	26.05	25.96	23.88	19.65	19.95	20.90	23.05
Gain (loss) on risk management contracts	26,543	4,493	(2,571)	(5,967)	–	–	–	–
Net income (loss)	16,254	7,013	4,684	(1,126)	226	9,270	2,597	(5,644)
Per share, basic and diluted ($)	0.05	0.02	0.01	0.00	0.00	0.03	0.01	(0.02)
Capital expenditures	57,700	80,262	48,044	49,360	22,749	24,326	27,315	19,101
Funds flow from operations (2)	19,716	23,809	23,161	23,037	20,735	32,609	22,823	10,039
Per share, basic and diluted ($)	0.06	0.07	0.07	0.08	0.07	0.11	0.08	0.03
Cash flow from operating activities (3)	10,242	25,587	24,042	18,517	23,772	33,090	20,592	3,244
Total assets (end of period)	837,773	785,538	765,233	747,763	652,216	648,554	647,839	613,738
Shares outstanding (000s)	335,638	335,638	335,638	328,398	300,425	296,306	296,122	296,108
Weighted average shares outstanding (000s)								
Basic	335,638	335,638	334,817	304,841	298,843	296,244	296,113	296,052
Diluted	335,638	335,638	335,244	305,874	300,768	298,584	299,693	300,768

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

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

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

Fluctuations in quarterly oil and gas sales and net income (loss) over the last eight quarters are primarily attributable to the volatility in crude oil prices and changes in sales volumes from new drilling activity, partially offset by natural declines in production. Production costs have increased in 2014 as the Company has begun to expense all costs related to Phase 1 of the ASP flood at Mooney. During 2013 polymer and injection costs related to Phase 1 of the ASP flood at Mooney were expensed (all other chemical costs were still being capitalized) and prior to 2013 all costs were being capitalized while the reservoir was being re-pressurized.

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		2014				2013			
	2014	2013	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Average Crude Oil Prices										
West Texas Intermediate (WTI) (US$/bbl)	**93.00**	97.98	**73.15**	**97.17**	**102.99**	**98.68**	97.46	105.83	94.29	94.34
Western Canadian Select (WCS) (Cdn$/bbl)	**81.08**	74.98	**66.73**	**83.80**	**90.42**	**83.39**	68.43	91.75	76.68	62.96
Differential – WCS/WTI (US$/bbl)	**19.60**	25.23	**14.39**	**20.24**	**20.08**	**23.11**	32.21	17.48	19.36	31.95
Differential – WCS/WTI (%)	**21.1%**	26.0%	**19.7%**	**20.8%**	**19.5%**	**23.4%**	33.1%	16.5%	20.6%	33.8%
Average Natural Gas Prices										
AECO gas (Cdn$/GJ)	**4.27**	3.00	**3.41**	**3.81**	**4.71**	**4.91**	2.99	2.67	3.40	2.92
Average Foreign Exchange (US$ per Cdn$1)	**0.905**	0.970	**0.881**	**0.918**	**0.917**	**0.906**	0.950	0.962	0.977	0.991

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.

During the first nine months of 2014 crude oil prices were strong; however, prices decreased sharply during the fourth quarter and the decrease in prices has continued in early 2015. The decrease has been attributed to a number of factors including rising global oil production, particularly increases in shale production in the US, a slowdown in demand due to weaker global economic conditions, a strong US dollar, increased inventory levels and geopolitical events in various oil producing areas. The sharp decrease in oil prices has led to a significant drop in planned drilling activity and capital spending in the industry. WTI oil prices averaged US$93.00 per bbl in 2014, down from US$97.98 per bbl in 2013. In the fourth quarter WTI oil prices averaged US$73.15 per bbl and WTI is approximately US$50.00 per bbl as of February 25, 2015.

WCS oil prices increased in 2014, averaging $81.08 per bbl in 2014 compared to $74.98 per bbl in 2013, due primarily to narrower heavy oil differentials. The differential in 2014 averaged US$19.60 per bbl, down from US$25.23 per bbl in 2013. The improvement in heavy oil differentials has been attributed to increased refining capacity that came on in 2014 (such as the expansion and reconfiguration of the BP facility at Whiting Indiana in the US that can now accommodate up to 350,000 bbls of heavy oil), additional pipeline capacity (the Flanagan South pipeline in the US was commissioned in 2014 and has capacity to transport up to 585,000 bbls of oil to the US Gulf Coast) and increased rail capacity to transport crude oil. While the pipeline and rail terminal expansions in 2014 alleviated some of the short-term transportation issues, take-away capacity remains an issue for oil producers in North America.

Currently, there are several pipeline proposals that could help to alleviate access problems from Western Canada's Sedimentary Basin to international markets, including the Keystone XL Pipeline (which could carry up to 585,000 bbls/d of oil to the Gulf Coast), the Northern Gateway Pipeline (which could carry up to 525,000 bbls/d of oil to Canada's west coast), the expansion of the existing Trans Mountain Express Pipeline (proposal is to 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 Energy East pipeline (which would carry up to 1.1 million bbls/d of oil from western Canada to refineries in eastern Canada and the east coast for export). All of these proposals would improve market access for Canadian crude oil; however, only the Northern Gateway pipeline has received regulatory approval for development. In general, these pipeline applications have garnered significant opposition from environmental and other groups and there is no assurance that any of these projects will get built.

Natural gas prices increased in 2014 averaging $4.27/GJ compared to $3.00/GJ in 2013. BlackPearl produces very little natural gas and therefore prices do not have a significant impact on our current oil and gas sales. However, we do consume gas in our Blackrod pilot operations and as we move toward commercial development of our two thermal projects the cost of gas will have a significant impact on our cost structure.

Changes in the value of the Canadian dollar relative to the US dollar impacts our revenues and cash flows as our oil sales price is determined by US benchmark prices. The Canadian dollar weakened against the US dollar in 2014 which has had a positive impact on our revenues and cash flows. The exchange rate between the Canadian dollar and the US dollar averaged Cdn$1 = US$0.91 during 2014 compared to Cdn$1 = US$0.97 in 2013. The Canadian dollar has continued to weaken relative to the US dollar in 2015, currently near Cdn$1 = US$0.80, which will have a positive impact on our revenues and cash flows.

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

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Daily production/sales volumes (1)				
Oil (bbls/d)	**8,567**	9,981	**8,492**	9,255
Natural gas (Mcf/d)	**3,294**	1,266	**2,492**	1,434
Combined (boe/d)	**9,116**	10,192	**8,907**	9,494
Bitumen – Blackrod (bbls/d) (2)	**523**	262	**380**	236
Total production (boe/d)	**9,639**	10,454	**9,287**	9,730
Product pricing (excluding risk management activities) (2)				
Oil ($/bbl)	**59.34**	58.44	**72.47**	65.09
Natural gas ($/Mcf)	**3.39**	3.50	**4.12**	3.16
Combined ($/boe)	**57.00**	57.67	**70.24**	64.11
Sales ($000s) (2)				
Oil and gas sales – gross	**47,798**	54,072	**228,345**	222,157
Royalties	**(9,655)**	(11,128)	**(43,870)**	(43,724)
Oil and gas sales – net	**38,143**	42,944	**184,475**	178,433

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

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

Oil and natural gas sales increased 3% in 2014 to $228.3 million from $222.2 million in 2013. The increase in oil and gas sales is attributable to a 10% increase in average sales prices received in 2014 compared to 2013, partially offset by a 6% decrease in production (on a boe basis).

Tighter heavy oil differentials and a weaker Canadian dollar relative to the US dollar contributed to an increase in our realized crude oil sales price during 2014. Our average oil wellhead sales price, prior to the impact of risk management activities, was $72.47 per bbl for 2014 compared with $65.09 per bbl in 2013.

The decrease in 2014 oil production is attributable to natural production declines at Onion Lake, as well as, selectively shutting-in some of our wells in the area to prepare for thermal activities in certain portions of the field. The Onion Lake field is a maturing area for primary production and many of the wells drilled over the last seven years have reached or are near the end of their productive life. During 2014 we drilled 20 wells in order to slow the Onion Lake field production decline. The decrease in 2014 production is also partially attributable to a decrease in capital spending on short-term production growth activities and the re-directing of our capital spending to the construction of the first phase of the Onion Lake thermal project.

Oil and natural gas sales decreased 12% in the fourth quarter of 2014 to $47.8 million from $54.1 million in the same period in 2013. The decrease in oil and gas sales is primarily attributable to an 11% decrease in production (on a boe basis) in Q4 2014 compared to the same period in 2013.

On a boe basis, 95% of the Company's oil and natural gas production in 2014 was heavy oil or bitumen. The Onion Lake area accounted for 46% and the Mooney area accounted for 37% of total production in 2014.

	Three months ended December 31		Year Ended December 31	
Production by area *(boe/d)*	**2014**	2013	**2014**	2013
Onion Lake	**4,651**	5,186	**4,263**	4,797
Mooney	**3,236**	3,837	**3,469**	3,685
John Lake	**1,109**	1,066	**1,067**	898
Other	**120**	103	**108**	114
Blackrod	**523**	262	**380**	236
	9,639	10,454	**9,287**	9,730

In 2011, BlackPearl commenced its SAGD pilot project at Blackrod. The pilot started with a single horizontal well pair and associated steam and water handling facilities. The pilot is being undertaken to provide operating data to design the commercial development of the Blackrod lands. All sales and expenses from the pilot are being recorded as an adjustment to the capitalized costs of the project until the technical feasibility and commercial viability of the project is established. Technical feasibility and commercial viability are confirmed when reserves are recognized, regulatory approval has been obtained and our Board of Directors has sanctioned commercial development. As of December 31, 2014, BlackPearl had not received regulatory approval for the commercial Blackrod project. A second pilot well pair was drilled in 2013 and steam injection in this well pair commenced during the fourth quarter of 2013. After the initial warm up phase the well pair was converted to SAGD mode (production test phase) in March 2014. Production is expected to ramp-up to peak rates in 2015. During 2014, the pilot wells produced on average 380 bbls/d of bitumen and the net revenues capitalized for 2014 were a loss of $2.4 million (2013 – $3.2 million).

Risk Management Activities

The Company will periodically enter into risk management contracts in order to ensure a certain level of cash flow to fund planned capital projects and to maintain as much financial flexibility as possible. BlackPearl's strategy mainly focuses on swaps and fixed price contracts to limit exposure to fluctuations in oil prices. The Company's risk management trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors and are not used for trading or speculative purposes. The current policy permits management to enter into risk management contracts up to 60% of budgeted production volumes for a maximum period of two years.

Gains and losses on risk management contracts include both realized gains and losses representing the portion of contracts that have been settled during the year and unrealized gains and losses that represent the non-cash change in the mark-to-market values of our outstanding risk management contracts. The Company realized a gain of $1.9 million on its risk management contracts during 2014. In addition, as a result of the recent drop in crude oil prices, we recorded an unrealized gain of $20.6 million in 2014.

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2014**	2013	**2014**	2013
Realized gain on risk management contracts	**5,846**	–	**1,870**	–
Per boe ($)	**6.97**	–	**0.58**	–
Unrealized gain on risk management contracts	**20,697**	–	**20,628**	–

The table below summarizes the Company's commodity contracts as at December 31, 2014:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,500 bbls/d	January 1, 2015 to March 31, 2015	CDN$ WCS	CDN$ 80.20/bbl	Swap
Oil	2,500 bbls/d	January 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap

The table below summarizes commodity contracts the Company has entered into subsequent to December 31, 2014:

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

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect on December 31, 2015 to exercise the option to enter into the oil swap.

Royalties

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Royalties ($000s)	**9,655**	11,128	**43,870**	43,724
Per boe ($)	**11.51**	11.87	**13.49**	12.62
As a percentage of oil and gas sales	**20%**	21%	**19%**	20%

BlackPearl makes royalty payments to the owners of the mineral rights on the lands we have leased. Most of the payments are to provincial governments or, in the case of our Onion Lake area production, to the Onion Lake Cree Nation. Royalties as a percentage of revenue decreased to 19% of revenues in 2014 from 20% of revenues in 2013 and in the fourth quarter of 2014 royalties were 20% of revenues compared to 21% of revenues in the same quarter in 2013.

The decrease in royalties as a percentage of oil and gas sales is primarily attributable to changes to the Alberta government's EOR royalty incentive program, which affects our Mooney area production. Under the new royalty scheme, production from the first phase of the ASP flood at Mooney will incur crown royalties under 10% for the next 8 to 10 years, effective retroactively to January 1, 2014. This resulted in a reduction in our previously paid royalties of approximately $1 million. Future expansion phases of the ASP flood should be eligible for a flat 5% royalty on production for the first 8 to 10 years of ASP flooding. In addition, royalties as a percentage of revenues is expected to continue to drop as a result of the commencement of production, later in 2015, from the Onion Lake EOR project. During the pre-payout period, royalties paid on revenues from this project are expected to be approximately 10%.

Transportation Costs

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Transportation costs ($000s)	**1,240**	1,657	**6,132**	9,588
Per boe ($)	**1.48**	1.77	**1.89**	2.77

Transportation costs are incurred to move marketable crude oil and natural gas to their selling points. Changes in transportation costs, on a boe basis, are generally related to moving crude oil to different sales points to capture better marketing opportunities. Transportation costs decreased 36% in 2014 to $6.1 million from $9.6 million in 2013 and in the fourth quarter of 2014 transportation costs decreased 25% compared to the same quarter in 2013. These decreases are mostly attributable to lower costs at Mooney, where we have increased the amount of production volumes we ship by rail. The travel distance to rail terminals is less than travel distance to pipeline terminals in the area resulting in lower costs.

Production Costs

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Production costs ($000s)	**21,066**	18,420	**82,051**	72,199
Per boe ($)	**25.12**	19.65	**25.24**	20.84

Production costs increased by 14% in 2014 to $82.1 million from $72.2 million in 2013. On a per boe basis, production costs increased 21% in 2014 to $25.24 per boe from $20.84 per boe in 2013. Production costs increased in Q4 2014 compared to the same period in 2013 by 14% and on a per boe basis by 28%.

The increase in production costs in 2014 is attributable to increased expenses at Onion Lake due to the relative maturity of the field (higher repairs, maintenance and workover costs) and the expensing, for the first time, of all operating costs associated with the first phase of the ASP flood at Mooney. Prior to 2013, all operating costs related to the ASP flood were being capitalized until the reservoir was re-pressurized. In 2013, it was evident that we were achieving a positive production response from the re-pressurization and we began to expense polymer and injection costs associated with the re-pressurization. In 2014, we began to see a consistent production response from the injection of alkali and surfactant and therefore, beginning in 2014, we began to expense all costs associated with the first phase of the ASP flood. A breakdown of the ASP related expenses is provided below.

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Polymer costs	**1,117**	1,009	**6,484**	5,966
Other chemical costs	**1,196**	2,614	**8,065**	9,576
Injection costs	**1,295**	677	**4,618**	2,867
Total ASP costs	**3,608**	4,300	**19,167**	18,409
ASP costs capitalized	**–**	(2,614)	**–**	(9,576)
ASP costs expensed in production costs	**3,608**	1,686	**19,167**	8,833

Operating Netback [1]

	Three months ended December 31		Year Ended December 31	
($/boe)	**2014**	2013	**2014**	2013
Revenues	**57.00**	57.67	**70.24**	64.11
Royalties	**11.51**	11.87	**13.49**	12.62
Transportation costs	**1.48**	1.77	**1.89**	2.77
Production costs	**25.12**	19.65	**25.24**	20.84
Operating netback excluding realized risk management contracts	**18.89**	24.38	**29.62**	27.88
Realized gain on risk management contracts	**6.97**	–	**0.58**	–
Operating netback including realized risk management contracts	**25.86**	24.38	**30.20**	27.88

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

Operating netback is the cash margin we receive from each barrel of oil equivalent sold. Operating netback, excluding realized gains on risk management activities, increased 6% in 2014 to $29.62 per boe from $27.88 per boe in 2013. The increase is primarily attributable to the increase in realized crude oil prices, partially offset by higher production costs.

General and Administrative Expenses (G&A)

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2014**	2013	**2014**	2013
Gross G&A expense	**2,417**	2,549	**10,587**	10,503
Operator recoveries	**(516)**	(480)	**(2,145)**	(1,869)
Net G&A expense	**1,901**	2,069	**8,442**	8,634
Per boe ($)	**2.27**	2.21	**2.60**	2.49

General and administrative expenses consist primarily of salaries and wages of employees, office rent, computer services, legal, accounting and consulting fees. Gross general and administrative costs increased slightly compared to 2013 due primarily to higher office rental expenses. Net general and administrative costs decreased in 2014 compared to 2013 due primarily to higher operator recoveries as a result of increased capital spending.

Stock-Based Compensation

	Three months ended December 31		Year Ended December 31	
($000s, except per boe)	**2014**	2013	**2014**	2013
Gross stock-based compensation	**2,462**	756	**6,422**	4,312
Recoveries from forfeitures	**(35)**	(112)	**(273)**	(484)
Net stock-based compensation before capitalization	**2,427**	644	**6,149**	3,828
Capitalized stock-based compensation	**(87)**	(16)	**(258)**	(408)
Net stock-based compensation	**2,340**	628	**5,891**	3,420
Per boe ($)	**2.79**	0.67	**1.81**	0.99

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

The increase in stock-based compensation expense in 2014 compared to 2013 reflects an increase in the number of options issued. In 2014, 12,124,500 options were granted, 1,839,833 options were exercised and 2,631,333 options expired during the year.

During 2014, $258,000 of stock-based compensation costs were capitalized to property, plant and equipment related to options granted to contractors who work exclusively on the development activities at the Onion Lake EOR project.

Finance Costs

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Gross interest & financing charges	**303**	177	**1,140**	1,069
Capitalized interest & financing charges	**(254)**	(8)	**(634)**	(226)
Net interest & financing charges	**49**	169	**506**	843
Accretion of decommissioning liabilities	**381**	364	**1,532**	1,094
Debt financing costs	**–**	(80)	**–**	1,012
Total finance costs	**430**	453	**2,038**	2,949

The decrease in total finance costs in 2014 compared to 2013 is primarily attributable to debt financing costs (primarily legal expenses) in 2013 related to a proposed $350 million second-lien senior secured term loan facility that was to be used for the development of the Onion Lake EOR project. Due to the volatility in the debt capital markets, we elected not to proceed with this financing.

The increase in accretion in 2014 compared to 2013 is primarily attributable to higher estimated costs of decommissioning compared to 2013 as a result of new activities (additional drilling and new infrastructure projects) in 2014.

During 2014, $634,000 of interest costs related to the construction of the thermal projects was capitalized.

The average interest rate on advances under the Company's credit facilities was 3.27% in 2014. This does not include the cost of standby fees charged on unutilized amounts of the credit facilities.

Depletion and Depreciation

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Depletion and depreciation ($000s)	**15,143**	19,788	**66,794**	72,083
Per boe ($)	**18.06**	21.10	**20.55**	20.80

The Company's properties are depleted on a unit of production basis based on estimated proven plus probable reserves. Depletion and depreciation expense decreased 7% in 2014 to $66.8 million from $72.1 million in 2013. Depletion and depreciation expense decreased in Q4 2014 23% compared to the same period in 2013. The annual and quarterly decrease in depletion is a result of lower production volumes in 2014.

On a boe basis, depletion and depreciation expense decreased to $20.55 per boe in 2014 as compared to $20.80 per boe in 2013. This decrease in depletion on a boe basis is primarily attributable to increased oil and gas reserves recognized in our 2014 third party reserves evaluation.

As of December 31, 2014, $201.7 million of expenditures included in property, plant and equipment that relate to the Onion Lake EOR project are not subject to depletion until production at this project begins. Exploration and evaluation assets of $166.3 million are also not subject to depletion.

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 flows and are used for impairment testing. As indicators periodically dictate and at minimum on an annual basis, the net book values of these CGU's are tested for impairment. No impairment was recorded in 2014 at any of the Company's CGUs due to the Company's core CGUs having significant proved plus probable reserves.

Interest Income

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Interest income *($000s)*	**16**	13	**531**	44

Interest income consists of interest earned on excess cash held by the Company. Interest income has increased as a result of higher average cash balances maintained by the Company during 2014 compared to 2013. The higher average cash balances maintained during 2014 was due primarily to the proceeds from the issuance of common shares in 2014.

Income Taxes

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Current income tax	**55**	27	**118**	71
Deferred income tax	**6,281**	354	**9,232**	3,734
Total income tax	**6,336**	381	**9,350**	3,805

BlackPearl did not pay cash income taxes in 2014 and does not expect to pay income taxes in 2015 as we have sufficient tax pools to shelter expected income. The current income tax expense for 2014 is a result of capital tax.

Deferred income tax expense was $9.2 million for 2014, for an effective tax rate of 26%. In 2013, our effective tax rate was 37%. The lower effective tax rate in 2014 is due to the Company recording previously unrecognized tax benefits as a result of a recent tax audit of certain prior year's tax returns.

The Company has the following estimated tax pools as at:

($000s, except for left-hand column)	Rate %	**Dec 31, 2014**	Dec 31, 2013
Canadian exploration expenses	100	**17,052**	34,798
Canadian development expenses	30	**130,374**	124,604
Canadian oil and gas property expenses	10	**9,205**	16,579
Undepreciated capital costs	10-30	**346,894**	191,459
Non-capital losses (various expiry dates)	100	**215,785**	226,856
Share issuance costs	5 years	**2,706**	659
Total estimated tax pools		**722,016**	594,955

At December 31, 2014, the Company had an additional $27 million of Canadian resource pools that are restricted due to the successor rules in Canada and may not be fully utilized.

Gain on Disposition of Petroleum and Natural Gas Properties

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Gain on disposition of petroleum and natural gas properties	**–**	3,636	**–**	3,636

In 2014, the Company did not dispose of any significant oil and gas properties. During 2013, the Company completed a minor property disposition of certain non-producing heavy oil properties in Saskatchewan for cash consideration of $5.0 million that resulted in a gain of $3.6 million.

RESULTS FROM OPERATIONS

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Net income ($000s)	**16,254**	226	**26,825**	6,449
Per share, basic ($)	**0.05**	0.00	**0.08**	0.02
Per share, diluted ($)	**0.05**	0.00	**0.08**	0.02

For the year ended December 31, 2014, the Company generated net income of $26.8 million compared to net income of $6.4 million in 2013. For the quarter ended December 31, 2014, the Company generated net income of $16.3 million compared to $0.2 million in the same period in 2013. The increase in income in 2014 is primarily attributable to the unrealized gains on risk management contracts and higher wellhead sales prices in 2014, partially offset by higher production costs and lower production volumes.

	Three months ended December 31		Year Ended December 31	
	2014	2013	**2014**	2013
Funds flow from operations [(1)] ($000s)	**19,716**	20,735	**89,723**	86,206
Per share, basic ($)	**0.06**	0.07	**0.27**	0.29
Per share, diluted ($)	**0.06**	0.07	**0.27**	0.29

(1) Funds flow from operations is a non-GAAP measure that represents cash flow from operating activities before decommissioning costs incurred and changes in non-cash working capital related to operations. Funds flow from operations and funds flow from operations per share do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Company's efficiency and its ability to fund a portion of its growth expenditures.

Funds flow from operations increased by 4% to $89.7 million during 2014 compared to $86.2 million in 2013. The increase in funds flow in 2014 is primarily a result of higher wellhead sales prices in 2014, partially offset by higher production costs and lower oil production volumes.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2014, the Company had a working capital deficiency (current assets less current liabilities) of $18.2 million. The working capital deficiency will be funded from cash flows from operating activities and the undrawn amount available on our credit facilities.

At December 31, 2014, the Company had $29 million drawn under its existing credit facilities and issued letters of credit in the amount of $20,000; leaving $121 million available to be drawn under these credit facilities. The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. The next scheduled Borrowing Base redetermination is to occur by May 31, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2015. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. BlackPearl was in compliance with this covenant throughout the year ended 2014.

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

The first phase of the Onion Lake EOR project is under construction. It is being designed for production of 6,000 bbls/d of oil and capital costs are expected to be approximately $220 million. At December 31, 2014, the Company had spent approximately $168 million on the first phase of the Onion Lake EOR project. The first phase of the project is being funded from amounts available from our credit facilities, proceeds from share issuances earlier in the year (aggregate gross proceeds of $88.4 million) and funds flow from operations. Construction is expected to be completed and first steam injection by mid-2015.

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

The Company did not pay dividends on its common shares in 2014 and it does not anticipate paying dividends in the near term. In addition, the terms and conditions of the Company's existing credit facility agreement restricts the payment of cash dividends to shareholders.

CAPITAL EXPENDITURES

During the year ended December 31, 2014, capital spending was $235.4 million, an increase from $93.5 million in 2013. The main components of the 2014 capital program was the commercial engineering design and construction of the Onion Lake EOR project and the drilling of 35 associated wells (production wells, steam injectors and service wells), the drilling of 20 conventional heavy oils wells at Onion Lake, seven horizontal wells at Mooney, six horizontal wells at John Lake and two horizontal wells at Reita Lake. In addition, 2014 capital spending included expansion of pipeline and road infrastructure at Mooney and the conversion of the second pilot well pair at Blackrod to the production test phase along with continued capitalization of net revenues from operating the Blackrod pilot.

Capital expenditures in the fourth quarter of 2014 were $57.7 million, an increase from $22.7 million during the same period in 2013. The main components of the capital spending program during the fourth quarter were the ongoing construction of the first phase of the Onion Lake EOR project and drilling two horizontal wells at Reita Lake.

	Three months ended December 31		Year Ended December 31	
($000s)	**2014**	2013	**2014**	2013
Land	**315**	1,060	**1,023**	2,085
Seismic	**71**	(54)	**(46)**	937
Drilling and completion	**15,774**	12,137	**67,266**	51,824
Equipment and facilities	**41,431**	9,535	**165,363**	33,499
Other	**109**	71	**133**	89
Total	**57,700**	22,749	**233,739**	88,434
Property acquisitions	**–**	–	**1,627**	5,057
Total capital expenditures	**57,700**	22,749	**235,366**	93,491
Property dispositions	**–**	(2,302)	**–**	(2,302)
Net capital expenditures	**57,700**	20,447	**235,366**	91,189

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, 2014. These obligations are expected to be funded from cash flows from operating activities and the Company's credit facilities.

($000s)	2015	2016	2017	2018	2019	Thereafter
Operating leases (1)	1,989	1,314	47	–	–	–
Electrical service agreement (2)	1,003	520	119	119	119	2,106
Transportation service agreement (3)	102	135	135	135	135	33
Capital commitments (4)	22,000	–	–	–	–	–
Decommissioning liabilities (5)	852	1,900	984	1,056	1,198	60,903
Long-term debt (6)	–	29,000	–	–	–	–
	25,946	32,869	1,285	1,310	1,452	63,042

(1) The Company has 21 months remaining on an operating lease for office space as at December 31, 2014. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional $5.3 million (including an estimate for operating costs) over the next 21 months. At December 31, 2014, no amounts were owed (2013 – no amounts owing).

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

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

(4) The Company entered into certain agreements pertaining to the construction of the Onion Lake EOR project.

(5) The Company also has ongoing obligations related to the decommissioning of well sites and facilities which have reached the end of their economic lives. The undiscounted estimated obligations associated with the retirement of the Company's oil and gas properties were $66.9 million as at December 31, 2014. Decommissioning programs are undertaken regularly in accordance with applicable legislative requirements.

(6) The credit facilities have no fixed terms of repayment. Based on the existing terms of the Company's credit facilities, the first possible mandatory repayment date may come in 2016 assuming the facility is not extended during the scheduled credit facility review in May 2015. At this time management expects the facility will be extended.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2014 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets, accounts payable and accrued liabilities and long-term debt. The fair value of cash and cash equivalents, trade and other receivables, deposits and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of the instruments. The fair value of the Company's long-term debt approximates its carrying value as the interest rates charged on this debt are comparable to current market rates. The fair values of the Company's risk management contracts are determined by discounting the difference between the contracted prices and published forward price curves as at the consolidated balance sheet date, using the remaining contracted oil volumes and a risk-free interest rate (based on published government rates).

Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and the US dollar will affect the Company's operating and financial results. As at December 31, 2014, the Company held US $1.0 million cash and cash equivalents, US $32,000 prepaid expenses and deposits and US $35,000 accounts payable and accrued liabilities.

The polymer for our ASP flood at Mooney is supplied by a US company and we are required to pay in US dollars. Fluctuations in exchanges rates will have an impact in the Company's cost of polymer. In 2014, we spent approximately US$5.4 million on polymer.

As at December 31, 2014, 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 income for the year would have been approximately $89,000 lower. An equal opposite impact would have occurred to net income 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, 2014, the Company held $2.9 million in cash at various major financial institutions throughout Canada and the USA. At December 31, 2014, one Canadian financial institution held over 64% of our cash and short-term deposits. Cash balances in excess of the Company's day-to-day requirements are invested in short-term deposits of less than 30 days.

The Company's receivables are primarily with oil and gas marketers, a government agency, a large financial institution and joint venture partners. Receivables from oil and natural gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate this risk by assessing the financial strength of its counterparty and entering into relationships with larger purchasers with established credit history. During 2014, the Company did not experience any collection issues with its marketers.

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

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. At December 31, 2014, the Company had a $4.0 million receivable related to the risk management contracts held during the year. During 2014, the Company did not experience any collection issues with its risk management contracts.

The Company typically does not obtain collateral or security from its joint venture partners or oil and natural gas marketers. 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 Corporation'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 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, 2014, if interest rates had been one percent higher, with all other variables held constant, after tax net income for the year would have been approximately $12,000 lower.

The Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2014, if interest rates had been one percent higher, with all other variables held constant, after tax net income for the year would have been approximately $71,000 higher.

Liquidity Risk

Liquidity risk is the risk the Company is unable to meet its financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company manages its liquidity risk by ensuring that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and opportunities to issue additional equity. As at December 31, 2014, the Company had $121 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 5% of the Company's total production and, as a result, any fluctuation in natural gas prices would have a nominal effect on current activities. When the Company's thermal projects are commercially developed, natural gas will become a major input cost to the Company.

As at December 31, 2014, if our average oil wellhead sales price decreased $1.00 with all other variables held constant including risk management contracts, after tax net income for the year would have been approximately $2.5 million lower (2013 – $2.7 million lower). An equal opposite impact would have occurred to net income had average oil wellhead sales price been $1.00 higher.

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

OFF-BALANCE-SHEET ARRANGEMENTS

The Company had no off-balance-sheet arrangements during the year ended 2014 or 2013. We do utilize operating leases in our normal course of business as disclosed under Contractual Obligations and Commitments.

RELATED-PARTY TRANSACTIONS

There was no related-party transactions during the year ended 2014 or 2013. Key management compensation has been disclosed in the Company's financial statements (note 16).

OUTSTANDING SHARE DATA AND STOCK OPTIONS

As at February 25, 2015, the Company had 335,638,226 common shares outstanding and 20,801,334 stock options outstanding under its stock-based compensation program.

OUTSTANDING LONG-TERM DEBT DATA

As at February 25, 2015, the Company had $68,000,000 amounts drawn under its existing credit facilities and had issued letters of credit in the amount of $20,000; leaving $81,980,000 available to be drawn under these credit facilities.

PROPOSED TRANSACTIONS

As of February 25, 2015, 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 2 through 5 to the consolidated financial statements.

(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 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 non-financial 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 commercial viability and technical feasibility is established and regulatory and Board approval is received.

(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 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 non-financial assets. The Company's oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserve evaluators.

If our proved and probable reserve estimates change by 10%, our depletion expense would have changed by approximately $1.6 million, assuming no other changes to our reserves.

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 management determines that the projects are technically feasible and commercially viable or that their value is impaired. Technical feasibility and commercial viability are confirmed when reserves are recognized, regulatory approval has been obtained and our Board of Directors has sanctioned the development. At December 31, 2014, $166.3 million has been excluded from depletion and has been shown separately on the Company's balance sheet.

Certain costs related to property, plant and equipment have been excluded from costs subject to depletion. These costs relate to the Onion Lake EOR project which is still under construction and has no associated production to date. At December 31, 2014, $201.7 million has been excluded from depletion and has been disclosed separately in the Company's financial statement notes.

(ii) Impairment

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. 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 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 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 tangible and E&E assets. The Company monitors internal and external indicators of impairment relating to its tangible and E&E assets. These indicators include changes in commodity prices, reserve volume and discount rates. The discount rate and a summary of the commodity price forecast used to assess CGU impairment in 2014 can be found per note 9 on the audited consolidated financial statements.

In 2014 and 2013 we have five CGU's, one for each of our core areas and two CGU's for some of our minor properties. The Company performed impairment test calculations at December 31, 2014 to assess whether the carrying value of the petroleum and natural gas properties were recoverable. These impairment test calculations utilized a 10% after tax discount rate. No impairment was recorded in 2014 at any of the Company's CGUs due to the Company's core CGUs having significant proved plus probable reserves and long reserve lives.

(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 rate 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 decommissioning liability:

	2014	2013
Undiscounted abandonment costs ($000s)	**$ 66,893**	$ 63,861
Risk-free rate	**2.49%**	2.55%
Inflation rate	**2%**	2%
Average years to reclamation	**10**	9

(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 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 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).

CHANGES IN ACCOUNTING POLICIES

The Company has adopted the following new and amended standards with a date of initial application of January 1, 2014.

IAS 32: Financial Instruments: Presentation – amendments to IAS 32 clarified the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. IAS 32 amendments required minimal disclosure changes in the Company's financial statements.

IAS 36: Impairment of Assets –amendments to IAS 36 requires entities to disclose the recoverable amount of impaired Cash Generating Units ("CGU"). IAS 36 amendments required minimal disclosure changes in the Company's financial statements as of January 1, 2014.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

In May 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") to replace IAS 11, "Construction Contracts", IAS 18, "Revenue" and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

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

RISKS AND UNCERTAINTIES

The Company is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. These risks and uncertainties include, but are not limited to, the following:

Financial risks

- Risk of fluctuating oil, natural gas prices and the cost of diluent;
- Risk of reducing demand for heavy oil and bitumen;
- Risk of fluctuating heavy oil differentials;
- Risk of a prolonged period of low oil prices;
- Risk of not meeting covenants associated with the Company's credit facilities;
- Risk of lenders reducing the amount of credit per the Company's credit facilities;
- Risk of the Company's ability to make payments on, and to refinance, its future indebtedness;
- Risk associated with securing the needed capital to carry out the Company's operations;
- Availability of adequate debt, equity financing and cash flow to fund planned expenditures;
- Risk of not paying dividends and the associated value of the Company's common shares;
- Risk of fluctuating foreign currency exchange rates;
- Risk of changes to interest rates;
- Risk of a third party failing to meet its obligations;
- Risk of potential financial loss associated with risk management contracts;
- Global economic conditions and financial uncertainty; and
- Risk of capital costs over-runs on large development projects.

Operational risks

- Ability to find, acquire, develop and commercially produce oil and natural gas reserves;
- Ability to explore and develop any oil and natural gas reserves the Company may have;
- Ability to generate or raise sufficient capital to make the necessary investments to replace or expand the Company's oil and gas reserves;
- Risk that expenditures made on future exploration, development or acquisition by the Company will not result in new discoveries of oil or natural gas in commercial quantities;
- Uncertainties associated with estimating the quantity of reserves and resources and the associated cash flows;
- Risk of market price fluctuations which may render the recovery of the reserves and resources uneconomic;
- Risk the Company's undeveloped reserves and resources may not be ultimately produced within the time period the Company has planned, at the costs the Company has budgeted or at all;
- Risks associated with the early stages of development of some of our large thermal projects;
- Uncertainties of the SAGD bitumen and ASP flood recovery processes;
- Risks and hazards typically associated with such oil and gas operations, including hazards such as fire, explosion, blow-outs, mechanical or pipe failure, sour gas releases, cratering and oil spills, acts of vandalism, or other unexpected or dangerous conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury;

- Risk of a termination of a lease, license or permit;
- Reliance on third parties for pipeline, processing facilities and other infrastructure;
- Uncertainties in regards to the supply of chemicals and diluent;
- Uncertainties in regards to the supply of water for our SAGD projects;
- Unforeseen title defects in the leases we hold; and
- Risks associated with future abandonment and reclamation costs.

Regulatory risks

- Risk of changes in government policies, especially related to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection, social instability or other political, economic or diplomatic developments in its operations;
- Environmental and safety risks related to its oil and gas properties;
- Risk from aboriginal claims; and
- Risk related to royalty regimes and changes to royalty regimes.

Other risks

- Risks of legal and regulatory claims;
- Geo-political risks;
- The risk of relying on key personnel;
- Conflict of interest risks;
- Risks associated with management's estimates and assumptions;
- Risks that the Company's insurance coverage is insufficient or unavailable to cover all loses that may occur in the Company's operations;
- Competition for, among other things, capital, undeveloped land, skilled labor and equipment leading to capital cost over-runs; and
- Weather and other natural disruptions.

Further information regarding these risks may be found under "Risk Factors" in the Company's Annual Information Form. Many of the previously mentioned risks 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.

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, 2014.

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, 2014, 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, 2014. Based on this evaluation, the officers concluded that as of December 31, 2014, 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, 2014 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

2014 GUIDANCE AND 2015 OUTLOOK

	2014		Initial 2015
	Guidance	Actual	Guidance
Production (boe/d)			
Annual average	10,000 – 10,500	9,287	8,000 – 9,000
Funds flow from operations ($millions)	80 – 85	90	15 – 20
Capital expenditures ($millions)	260 – 270	236	70 – 75
Year-end debt ($millions)	95 – 105	47 (1)	125 – 130
Pricing Assumptions (annual average)			
Crude oil – WTI	US$92.00	US$93.00	US $55.00
Light/heavy differential	US$21.00	US$19.60	US $15.00
Foreign Exchange (Cdn$ to US$)	0.94	0.91	0.85

(1) Includes a working capital deficiency of $18 million as at December 31, 2014.

2014 Guidance Compared to Actual

BlackPearl's average oil and gas production of 9,287 boe/day was below the initial guidance we provided for the year. The lower production volumes were primarily attributable to reduced drilling activity at Mooney, as well as a postponement of the expansion of the ASP flood on phase two lands at Mooney.

Funds flow from operations was above guidance primarily as a result of higher crude oil prices, lower heavy oil differentials and a weaker Canadian dollar relative to the US dollar. These components resulted in our actual wellhead price averaging $72.47 a barrel compared to $65.91 a barrel assumed in our guidance. The benefits of a higher oil prices were partially offset by the lower production volumes described above. Funds flow from operations was also positively impacted by lower G&A expenses than we had forecast (lower salary and wage expense and higher operator recoveries) and lower transportation expenses (we trucked more oil to nearby rail terminals than we had originally forecast).

Capital expenditures of $235 million in 2014 were below our guidance range of $260 to $270 million. Lower capital expenditures in 2014 was primarily due to certain expenditures related to the Onion Lake thermal EOR project that were planned for 2014 being deferred to the first quarter of 2015. The reduced activity at Mooney also contributed to lower capital spending than originally planned.

Lower capital spending and higher funds flow from operations contributed to lower year-end debt levels than originally estimated.

2015 Initial Guidance

The dramatic drop in crude oil prices in the last few months will have a significant negative impact on our funds flow from operations and, as a result, we will curtail or defer our capital spending programs in certain areas. In 2015, we are planning to spend $70 to $75 million on capital projects. Our major focus in 2015 will be the completion of the Onion Lake thermal project, which will account for over 80% of our 2015 spending. Planned expansion of the ASP flood at Mooney (well conversions and initial capitalization of polymer and chemical costs) and conventional heavy oil drilling at Onion Lake and John Lake have been deferred due to the current low oil price environment. The Company is optimistic in the longer term outlook for oil prices but we had to adjust our capital spending to maintain financial flexibility. If oil prices improve, the Company is in a position to resume our capital plans.

The capital program is expected to be funded from a combination of anticipated funds flow from operations, which we are budgeting to be between $15 and $20 million and supplemented with our existing credit facilities. Year-end 2015 debt levels are anticipated to be between $125 and $130 million.

As a result of curtailing some of our short term production growth projects in our capital spending plans, we anticipate oil and gas production to average between 8,000 and 9,000 boe/d in 2015. We expect to complete construction and commence steam injection in mid-2015 at the Onion Lake thermal project but this is not expected to have a meaningful impact on our production levels until 2016. Exit production levels for 2015 are expected to be between 9,000 and 10,000 boe/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.

Sensitivities

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

The following table summarizes the approximate effect changes in these factors could have on the Company's 2015 performance:

($millions)	Funds Flow	Net Income
Price change		
CDN$5 per bbl change in our realized oil price	12.7	9.4
CDN$1 per bbl change in production costs	3.1	2.3
Exchange rate		
$0.02 change in US/CDN rate	1.7	1.3
Production rate		
500 bbl per day change	1.8	(1.1)

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 "anticipated", "approximately", "planning", "planned", "could", "continued", "estimate", "estimates", "estimated", "forecast", "likely", "expect", "expected", "may", "target", "intends", "intended", "new", "will", "timing", "in the event", "move toward", "is to occur", "scheduled", "outlook" or similar words suggesting future outcomes.

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

- Potential production levels and anticipated timing of initial and peak oil production at the Onion Lake EOR project as discussed in the 2014 Significant Events section;
- Target date for completion of construction and first steam at the Onion Lake EOR project as discussed in the 2014 Significant Events section;
- The volumes and estimated value of BlackPearl's proved and probable reserves in the 2014 significant events section;
- The volumes and estimated value of BlackPearl's contingent resources in the 2014 significant events section;
- Future oil and gas prices and their impact on BlackPearl as discussed in the Commodity Prices section;
- Expected future gas prices and their impact on costs related to our thermal projects as discussed in the Commodity Prices section;

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

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

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

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

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. In the case of the contingent resources assigned to BlackPearl's three core projects the contingencies include:

- At Blackrod the requirement for more evaluation drilling, as required by regulatory process, to define the reservoir characteristics to assist in the implementation and operating of the SAGD process, the absence of submission of an application to expand the commercial SAGD development and the uncertainty of timing of production and development.
- At Onion Lake the absence of approval to extend the SAGD development area, the requirement for more evaluation drilling to define the reservoir characteristics of the resource to assist in the implementation and operating of the SAGD recovery process, the uncertainty of company commitment for expansion of the commercial SAGD development and the uncertainty of timing of production and development.
- At Mooney the requirement for more evaluation wells to further define reservoir and fluid characteristics and the uncertainty of timing of producing and development of the entire field.

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. Please refer to our Annual Information Form for a more detailed discussion of these contingencies.

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, 2014. 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 25, 2015 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 25, 2015

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, 2014 and December 31, 2013, and the consolidated statements of comprehensive income, 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, 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 audits 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, 2014 and December 31, 2013, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
February 25, 2015

Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

(audited)

(Cdn$ in thousands)	Note	December 31, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents	6	$ 2,918	$ 8,402
Trade and other receivables	7	18,467	20,586
Inventory		638	–
Prepaid expenses and deposits		1,000	963
Risk management assets	18	20,628	–
		43,651	29,951
Trade and other receivables	7	–	1,038
Deferred tax assets	15	–	408
Exploration and evaluation assets	8	166,344	161,408
Property, plant and equipment	9	627,778	459,411
		$ 837,773	$ 652,216
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 61,036	$ 37,895
Current portion of decommissioning liabilities	12	852	838
		61,888	38,733
Decommissioning liabilities	12	59,831	54,546
Long-term debt	13	29,000	–
Deferred tax liabilities	15	8,018	–
		158,737	93,279
Shareholders' equity			
Share capital	14	970,134	881,949
Contributed surplus		33,788	28,699
Deficit		(324,886)	(351,711)
		679,036	558,937
		$ 837,773	$ 652,216

Commitments and contingencies (note 17)

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 INCOME

(audited)

(Cdn$ in thousands, except for per share amounts)	Note	Year ended December 31, 2014	Year ended December 31, 2013
Revenue			
Oil and gas sales		$ 228,345	$ 222,157
Royalties		(43,870)	(43,724)
Net oil and gas revenue		184,475	178,433
Gain on risk management contracts	18	22,498	–
		206,973	178,433
Expenses			
Production		82,051	72,199
Transportation		6,132	9,588
General and administrative		8,442	8,634
Depletion and depreciation	9	66,794	72,083
Impairment of property, plant and equipment	9	–	3,000
Finance costs	19	2,038	2,949
Stock-based compensation	14	5,891	3,420
Foreign currency exchange gain		(19)	(14)
		171,329	171,859
Other income			
Interest income		531	44
Gain on disposition of petroleum and natural gas properties		–	3,636
		531	3,680
Income before income taxes		36,175	10,254
Income taxes			
Current income tax	15	118	71
Deferred income tax	15	9,232	3,734
		9,350	3,805
Net and comprehensive income for the year		$ 26,825	$ 6,449
Income per share			
Basic	14	$ 0.08	$ 0.02
Diluted	14	$ 0.08	$ 0.02

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(audited)

(Cdn$ in thousands)				Year ended December 31, 2014
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2014	$ 881,949	$ 28,699	$ (351,711)	$ 558,937
Net and comprehensive income for the year	–	–	26,825	26,825
Stock-based compensation	–	6,149	–	6,149
Shares issued on equity offering	88,440	–	–	88,440
Share issue costs	(3,361)	–	–	(3,361)
Shares issued on exercise of stock options	2,046	–	–	2,046
Transfer to share capital on exercise of stock options	1,060	(1,060)	–	–
Balance – December 31, 2014	**$ 970,134**	**$ 33,788**	**$ (324,886)**	**$ 679,036**

				Year ended December 31, 2013
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance – January 1, 2013	$ 876,400	$ 26,761	$ (358,160)	$ 545,001
Net and comprehensive income for the year	–	–	6,449	6,449
Stock-based compensation	–	3,828	–	3,828
Shares issued on exercise of stock options	3,659	–	–	3,659
Transfer to share capital on exercise of stock options	1,890	(1,890)	–	–
Balance – December 31, 2013	$ 881,949	$ 28,699	$ (351,711)	$ 558,937

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(audited)

(Cdn$ in thousands)	Note	Year ended December 31, 2014	Year ended December 31, 2013
Operating activities			
Net and comprehensive income for the year		$ 26,825	$ 6,449
Items not involving cash:			
Depletion and depreciation	9	66,794	72,083
Impairment of property, plant and equipment	9	–	3,000
Accretion of decommissioning liabilities	12	1,532	1,094
Stock-based compensation	14	5,891	3,420
Foreign exchange loss		77	62
Deferred income tax	15	9,232	3,734
Gain on disposition of petroleum and natural gas properties		–	(3,636)
Unrealized gain on risk management contracts	18	(20,628)	–
Decommissioning costs incurred	12	(963)	(849)
Changes in non-cash working capital	19	(10,372)	(4,659)
Cash flow from operating activities		78,388	80,698
Financing activities			
Proceeds on issue of common shares, net of costs	14	86,316	3,659
Proceeds on issue of long-term debt	13	29,000	25,000
Repayment of long-term debt	13	–	(25,000)
Cash flow from financing activities		115,316	3,659
Investing activities			
Capital expenditures - exploration and evaluation assets	8	(8,877)	(26,275)
Capital expenditures - property, plant and equipment	9	(226,231)	(66,808)
Proceeds from disposition of petroleum and natural gas properties		–	5,011
Changes in non-cash working capital	19	36,016	(4,784)
Cash flow used in investing activities		(199,092)	(92,856)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(96)	(76)
Decrease in cash and cash equivalents		(5,484)	(8,575)
Cash and cash equivalents, beginning of year		8,402	16,977
Cash and cash equivalents, end of year		$ 2,918	$ 8,402

See accompanying notes to consolidated financial statements

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

(audited)

1. GENERAL INFORMATION

BlackPearl Resources Inc. (collectively with its subsidiaries, the "Company" or "BlackPearl") is engaged in the business of oil and gas exploration, development and production in North America. The Company's primary focus is on heavy oil and oil sands projects in Western Canada. The Company's common shares are listed and traded on the TSX Exchange under the trading symbol "PXX". The Company's Swedish Depository Receipts trade on the NASDAQ Stockholm market under the symbol "PXXS". BlackPearl is incorporated and located in Canada. The address of its registered office is 700, 444 – 7th Avenue SW, Calgary, Alberta, T2P 0X8.

2. BASIS OF PREPARATION

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The policies applied in these consolidated financial statements are based on IFRS issued, effective and outstanding as of February 25, 2015, the date they were approved and authorized for issuance by the Board of Directors ("the Board").

3. CHANGES IN ACCOUNTING POLICIES

Except for the changes below, the Company has consistently applied the accounting policies set out in note 4 to all periods presented in these consolidated financial statements. The Company has adopted the following new standards and amendments with an initial application date of January 1, 2014.

IAS 32: Financial Instruments: Presentation – amendments to IAS 32 clarified the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. IAS 32 amendments required minimal disclosure changes in the Company's financial statements.

IAS 36: Impairment of Assets – amendments to IAS 36 requires entities to disclose the recoverable amount of impaired Cash Generating Units. IAS 36 amendments required minimal disclosure changes in the Company's financial statements.

4. 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, 2014. 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, 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. 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 measured at amortized cost at the settlement date using the effective interest rate method of amortization.

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.

The Company has no financial assets or financial liabilities that give rise to other comprehensive income. 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.

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.

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, commercial and management review, as well as a review for indicators of impairment at least once a year. 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 are confirmed when reserves are recognized, regulatory approval has been obtained and our Board has sanctioned the development.

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.

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 of 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.

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 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. 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 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, or on a different tax entities, but 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 from equity.

Income per share

Basic income per share is calculated by dividing the net income for the period attributable to equity owners of BlackPearl by the weighted average number of common shares outstanding during the period. Diluted income per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments 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 period. The Company's potentially dilutive instruments comprise stock options.

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 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. 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 issuances of the Company's financial statements are listed below.

In May 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") to replace IAS 11, "Construction Contracts", IAS 18, "Revenue" and a number of revenue-related interpretations. IFRS 15 specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more informative, relevant disclosures. IFRS 15 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Company's consolidated financial statements.

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

5. 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 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. 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 non-financial 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 and regulatory and Board approval is received.

(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 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 non-financial 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 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 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 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. Note 9 to the consolidated financial statements disclose the discount rate used to assess CGU impairment in 2014.

Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of tangible and E&E assets. The Company monitors internal and external indicators of impairment relating to its tangible and E&E assets. These indicators include changes in commodity prices, reserve volume and discount rates. Note 9 to the consolidated financial statements summarize the commodity price forecast used to assess CGU impairment in 2014.

(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 rate 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.

(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 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 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).

6. CASH AND CASH EQUIVALENTS

	2014	2013
Cash at financial institutions	$ 2,918	$ 8,402

Cash at financial institutions earns interest at floating rates based on daily deposit rates. As of December 31, 2014, US $1.0 million (2013 – US $1.1 million) is included in cash at financial institutions. The Company only deposits cash with major financial institutions of high quality credit ratings.

7. TRADE AND OTHER RECEIVABLES

	2014	2013
Trade accounts receivable	$ 12,249	$ 16,845
Receivables from joint arrangements	309	305
Allowance for doubtful accounts	(285)	(285)
Net accounts receivable	12,273	16,865
Royalty reimbursement from enhanced oil recovery incentive programs	1,038	4,072
Receivable from risk management contracts	4,059	–
Other receivables	1,097	687
Total trade and other receivables	18,467	21,624
Less non-current portion of royalty reimbursement from enhanced oil recovery incentive programs	–	(1,038)
Current portion of trade and other receivables	$ 18,467	$ 20,586

Aging of trade accounts receivables are as follows:

	2014	2013
Current	$ 12,232	$ 16,443
31 to 60 days	9	322
61 to 90 days	8	46
Over 90 days	–	34
	$ 12,249	$ 16,845

8. EXPLORATION AND EVALUATION ASSETS

At January 1, 2013	$ 134,721
Expenditures	24,181
Acquisition	2,094
Capitalized stock-based compensation	148
Change in decommissioning provision	264
At December 31, 2013	161,408
Expenditures	7,250
Acquisition	1,627
Change in decommissioning provision	609
Transfers to property, plant & equipment	(4,550)
At December 31, 2014	$ 166,344

The Company's exploration and evaluation assets consist predominately of costs pertaining to the Blackrod SAGD project in northern Alberta. These assets are not subject to depletion or depreciation but they are reviewed for possible impairment. During 2014, no assets were considered to be impaired.

The net operating revenues of the Blackrod SAGD pilot are being capitalized until transfer from exploration and evaluation assets to property, plant and equipment occurs. The transfer of exploration and evaluation assets to property, plant and equipment occurs when commercial viability and technical feasibility is established and regulatory and Board approval is received which is based, in part, on proved and probable reserves recognized for the asset. During the year ended December 31, 2014 the Company capitalized net operating revenues totalling a loss of $2.4 million (2013 – loss of $3.2 million). The Company did not capitalize any general and administrative costs related to exploration activities during the year ended December 31, 2014 (2013 – $Nil).

9. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Corporate	Total
Cost			
At January 1, 2013	$ 848,108	$ 3,352	$ 851,460
Expenditures	63,755	90	63,845
Acquisitions	2,963	–	2,963
Capitalized stock-based compensation	260	–	260
Change in decommissioning provision	22,279	–	22,279
Disposals	(2,302)	–	(2,302)
At December 31, 2013	935,063	3,442	938,505
Expenditures	226,177	54	226,231
Capitalized stock-based compensation	258	–	258
Change in decommissioning provision	4,122	–	4,122
Transfers from exploration & evaluation assets	4,550	–	4,550
At December 31, 2014	$ 1,170,170	$ 3,496	$ 1,173,666
Accumulated depletion and depreciation			
At January 1, 2013	$ 402,256	$ 1,905	$ 404,161
Depletion and depreciation	71,870	213	72,083
Impairment	3,000	–	3,000
Disposals	(150)	–	(150)
At December 31, 2013	476,976	2,118	479,094
Depletion and depreciation	66,598	196	66,794
Impairment	–	–	–
At December 31, 2014	$ 543,574	$ 2,314	$ 545,888
Net book value			
December 31, 2013	$ 458,087	$ 1,324	$ 459,411
December 31, 2014	$ 626,596	$ 1,182	$ 627,778

The calculation of depletion for the year ended December 31, 2014 included estimated future development costs of $138 million (2013 – $117 million) associated with the development of the Company's proved plus probable reserves. During the year ended December 31, 2014, the Company capitalized borrowing costs of $0.6 million (2013 – $0.2 million) to development activities. The Company did not capitalize any general and administrative costs related to development activities during the year ended December 31, 2014 (2013 – $Nil).

Property, plant and equipment at December 31, 2014 includes $201.7 million (December 31, 2013 – $16.0 million) of assets under construction pertaining to the Onion Lake Enhanced Oil Recovery (EOR) project that are not subject to depletion and depreciation.

The Company performed impairment test calculations at December 31, 2014 to assess whether the carrying value of the petroleum and natural gas properties were recoverable. These impairment test calculations utilized a 10% after tax discount rate. No impairment was recorded in 2014 (2013 – $3 million) at any of the Company's CGUs due to the Company's core CGUs having significant proved plus probable reserves and long reserve lives and the Company's minor CGUs having incurred impairment losses in prior years. A one percent increase in the assumed discount rate or a ten percent decrease to the forward commodity price estimates would not result in impairment at any of the Company's CGUs.

At December 31, 2014, the estimated recoverable amount of the Company's previously impaired CGU was $0.1 million at the Salt Lake CGU in Saskatchewan.

The following represent the prices that were used in the December 31, 2014 impairment tests:

Average Price Forecast (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$)
2015	65.00	60.50	3.32	0.850
2016	80.00	75.13	3.71	0.870
2017	90.00	84.52	3.90	0.870
2018	91.35	85.79	4.47	0.870
2019	92.72	87.07	5.05	0.870
2020	94.11	89.31	5.13	0.870
2021	95.52	90.65	5.22	0.870
2022	96.96	92.01	5.31	0.870
2023	98.41	93.39	5.40	0.870
2024	99.89	94.79	5.49	0.870
2025	101.38	96.21	5.58	0.870
Escalation rate of 1.5% thereafter (4)				

(1) The benchmark prices listed above 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 2025 to the end of the reserve life.

10. PROPERTY ACQUISITION

The Company completed a minor property acquisition during the year ended 2014 for net cash considerations of $1.6 million. The assets acquired included oil sands acreage in the Reita Lake area, as well as minor natural gas production. Decommissioning liabilities acquired as part of the property acquisition were $0.5 million. This property acquisition was completed with full tax pools and no working capital or debt obligations were assumed.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2014	2013
Trade payables and accrued liabilities	$ 60,065	$ 37,159
Payables to joint arrangements	570	359
Other payables	401	377
	$ 61,036	$ 37,895

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

12. 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 and processing facilities. The total undiscounted amount of the estimated cash flows required to settle the liability is approximately $66.9 million (2013 – $63.9 million). The estimated net present value of the decommissioning liability was calculated using an inflation factor of 2% (2013 – 2%) and discounted using a risk-free rate of 2.49% (2013 – 2.55%). Settlement of the liability, which may extend up to 40 years in the future, is expected to be funded from general corporate funds at the time of retirement.

Changes to the decommissioning liability were as follows:

	2014	2013
Decommissioning liability, beginning of year	$ 55,384	$ 33,372
New liabilities recognized	4,261	2,103
Liabilities acquired	470	6,589
Reduction in liabilities due to asset dispositions	(210)	(789)
Decommissioning costs incurred	(963)	(849)
Change in estimated costs of decommissioning	–	14,815
Change in discount rate	209	(951)
Accretion expense	1,532	1,094
Decommissioning liability, end of year	60,683	55,384
Less current portion of decommissioning liability	(852)	(838)
Non-current portion of decommissioning liability	$ 59,831	$ 54,546

13. LONG-TERM DEBT

At December 31, 2014 the Company had credit facilities of $150 million, consisting of a $140 million syndicated revolving line of credit (2013 – $105 million) and a non-syndicated operating line of credit of $10 million (2013 – $10 million). The facilities are secured by a floating and fixed charge debenture on the assets of the Company. The amount available under these facilities ("Borrowing Base") is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. The next scheduled Borrowing Base redetermination is to occur by May 31, 2015. The facilities are also subject to annual reviews by the lenders and the next scheduled review is to be completed by May 31, 2015. In the event the lenders elected not to renew the credit facilities during the annual review, any amounts outstanding on the facilities would be due and payable in full by May 30, 2016.

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

At December 31, 2014, the Company had $29 million (2013 – $Nil) drawn under its existing credit facilities and issued letters of credit in the amount of $20,000 (2013 – $20,000); leaving $121 million (2013 – $115 million) available to be drawn under these credit facilities.

Pursuant to the terms of the credit agreement, the Company is required to maintain a working capital ratio of 1:1 at the end of each fiscal quarter. Working capital as defined in the lending agreement is current assets, as indicated on the Company's consolidated balance sheet, plus any undrawn amount on the credit facilities compared to current liabilities from the Company's consolidated balance sheet. In addition, amounts related to risk management contracts are excluded from the calculations of current assets and current liabilities. The Company had a working capital ratio of 2.3:1 at December 31, 2014 (2013 – 3.7:1) and is in compliance with this covenant at December 31, 2014.

14. 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, 2013	295,765,808	$ 876,400
Shares issued on exercise of stock options	4,659,000	3,659
Transferred from contributed surplus on exercise of stock options	–	1,890
Balance as at December 31, 2013	300,424,808	881,949
Shares issued on equity offering	33,373,585	88,440
Share issue costs, net of tax benefits of $806	–	(3,361)
Shares issued on exercise of stock options	1,839,833	2,046
Transferred from contributed surplus on exercise of stock options	–	1,060
Balance as at December 31, 2014	335,638,226	$ 970,134

(c) Stock Options Outstanding

The Company has a stock option plan (the "Plan") available to directors, officers, employees and certain consultants of the Company and its subsidiaries. Under the Plan, the number of common shares to be reserved and authorized for issuance pursuant to options granted under the Plan cannot exceed 10% of the total number of issued and outstanding shares in the Company. The term and the vesting period of any options granted are determined at the discretion of the Board. The maximum term for options granted is ten years; however, all of the options granted by the Company have a term of five years or less. As well, except for specific options granted this year where one third vested at the time of the grant as approved by the Board, all other options vest at a rate of one third on each of the three anniversaries from the date of the grant. The exercise price of the option cannot be less than the five-day volume weighted average trading price of the common shares immediately preceding the day the option is granted.

The following table summarizes stock options outstanding:

	Number of Options	Weighted Average Exercise Price ($)
Outstanding at January 1, 2013	17,382,999	2.81
Granted	3,545,500	2.39
Exercised	(4,659,000)	0.79
Forfeited	(1,638,000)	3.69
Expired	(25,000)	1.75
Outstanding at December 31, 2013	14,606,499	3.26
Granted	12,124,500	2.30
Exercised	(1,839,833)	1.11
Forfeited	(1,343,498)	3.58
Expired	(2,631,333)	2.21
Outstanding at December 31, 2014	20,916,335	3.00

Options outstanding and exercisable as at December 31, 2014 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)
1.62 – 3.00	14,845,667	2.31	4.14	2,446,073	1.97	4.02
3.01 – 4.50	1,919,834	3.68	2.43	1,312,688	3.67	2.39
4.51 – 6.00	3,835,834	5.01	1.38	3,835,834	5.01	1.38
6.01 – 7.50	240,000	6.68	1.48	240,000	6.68	1.48
7.51 – 7.66	75,000	7.66	1.30	75,000	7.66	1.30
	20,916,335	3.00	3.44	7,909,595	3.92	2.37

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, 2014, 12,124,500 options were granted (2013 – 3,545,500).

The fair value of these options was estimated using the following weighted average assumptions:

Assumptions	**Year ended December 31, 2014**	Year ended December 31, 2013
Risk free interest rate (%)	**1.3**	1.1
Dividend yield (%)	**0.0**	0.0
Expected life (years)	**3.7**	3.5
Expected volatility (%)	**50.7**	49.3
Forfeiture rate (%)	**14.8**	14.2
Weighted average fair value of options	**$ 0.89**	$ 0.90

(d) Stock-based Compensation

	Year ended December 31, 2014	Year ended December 31, 2013
Gross stock-based compensation	$ 6,422	$ 4,312
Recoveries from forfeitures	(273)	(484)
Net stock-based compensation before capitalization	6,149	3,828
Stock-based compensation capitalized to exploration and evaluation assets	–	(148)
Stock-based compensation capitalized to property, plant and equipment	(258)	(260)
Net stock-based compensation	$ 5,891	$ 3,420

(e) Income per Share

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

The following tables shows the calculation of basic and diluted income per share:

	Year ended December 31, 2014	Year ended December 31, 2013
Net and comprehensive income	$ 26,825	$ 6,449
Weighted average number of common shares – basic	327,806	296,819
Dilutive effect:		
Outstanding options	158	3,327
Weighted average number of common shares – diluted	327,964	300,146
Basic income per share	$ 0.08	$ 0.02
Diluted income per share	$ 0.08	$ 0.02

The Company used a weighted average market closing price of $2.05 (2013 – $2.19) per share to calculate the dilutive effect of stock options. In 2014, 18,752,341 options were anti-dilutive (2013 – 12,921,529) and were not included in the calculation of diluted net income per share.

15. 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, 2014	Year ended December 31, 2013
Income before income taxes	$ 36,175	$ 10,254
Corporate income tax rate	25.78%	25.76%
Computed income tax expense	$ 9,326	$ 2,641
Increase (decrease) resulting from:		
Change in unrecognized deferred income tax assets	(1,459)	451
Non-deductible expenses	1,519	881
Change in enacted tax rates	–	(254)
Other	(154)	15
Current income tax expense	118	71
Income tax expense	$ 9,350	$ 3,805
Effective tax rate	25.85%	37.11%

(b) Deferred income tax

At December 31, 2014, deferred tax liabilities of $8.0 million (2013 – deferred tax assets of $0.4 million) have been recognized in the consolidated financial statements.

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

	January 1, 2014	(Charges) / credits due to other	(Charged) / credited to earnings	December 31, 2014
Deferred income tax assets:				
Decommissioning liabilities	$ 14,133	$ –	$ 1,376	$ 15,509
Income tax losses carried forward	58,196	–	(2,806)	55,390
Share issue costs	169	806	(281)	694
	72,498	806	(1,711)	71,593
Deferred income tax liabilities:				
Property, plant and equipment	(72,090)	–	(2,226)	(74,316)
Risk management contracts	–	–	(5,295)	(5,295)
	(72,090)	–	(7,521)	(79,611)
Net deferred income tax assets (liabilities)	$ 408	$ 806	$ (9,232)	$ (8,018)

	January 1, 2013	(Charges) / credits due to other	(Charged) / credited to earnings	December 31, 2013
Deferred income tax assets:				
Decommissioning liabilities	$ 8,272	$ –	$ 5,861	$ 14,133
Income tax losses carried forward	62,160	–	(3,964)	58,196
Share issue costs	448	–	(279)	169
	70,880	–	1,618	72,498
Deferred income tax liabilities:				
Property, plant and equipment	(66,738)	–	(5,352)	(72,090)
Risk management contracts	–	–	–	–
	(66,738)	–	(5,352)	(72,090)
Net deferred income tax assets (liabilities)	$ 4,142	$ –	$ (3,734)	$ 408

(c) Unrecognized deferred tax assets

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 2014 or 2013.

16. 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 comprehensive statement of income:

	Year ended December 31, 2014	Year ended December 31, 2013
Production expense (1)	$ 1,371	$ 1,178
General and administrative expense	5,382	5,531
Stock-based compensation	5,891	3,420
	$ 12,644	$ 10,129

(1) Excludes compensation paid to contractors and consultants.

(b) Key management compensation

Key management includes the Company's directors and officers. At December 31, 2014, directors and senior management consisted of nine individuals (2013 – nine individuals). Compensation awarded to key management includes short-term employee benefits which consist of salary and benefits during the year and stock-based compensation.

The following table summarizes the compensation of key management:

	Year ended December 31, 2014	Year ended December 31, 2013
Short-term employee benefits	$ 1,669	$ 1,475
Stock-based compensation	3,020	838
	$ 4,689	$ 2,313

17. COMMITMENTS AND CONTINGENCIES

	2015	2016	2017	2018	2019	Thereafter
Operating leases (1)	$ 1,989	$ 1,314	$ 47	$ –	$ –	$ –
Electrical service agreement (2)	1,003	520	119	119	119	2,106
Transportation service agreement (3)	102	135	135	135	135	33
Capital commitments (4)	22,000	–	–	–	–	–
	$ 25,094	$ 1,969	$ 301	$ 254	$ 254	$ 2,139

(1) The Company has 21 months remaining on an operating lease for office space as at December 31, 2014. The Company's office lease was executed jointly with another party. Under the terms of the lease, BlackPearl and the other party are joint and severally liable for the obligations pursuant to the lease. Accordingly, if the other party is unable to fulfill their lease obligation, BlackPearl would be required to pay a maximum additional amount of $5.3 million (including an estimate for operating costs) over the next 21 months. At December 31, 2014, no amounts were owed (2013 – no amounts owing).

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

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

(4) The Company entered into certain agreements pertaining to the construction of the Onion Lake EOR project.

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments as at December 31, 2014 include cash and cash equivalents, trade and other receivables, deposits within prepaid expenses and deposits, risk management assets, accounts payable and accrued liabilities and long-term debt.

(a) Fair value of financial instruments

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

		December 31, 2014		December 31, 2013	
	Measurement Level	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets					
Loans and receivables:					
Cash and cash equivalents	1	$ 2,918	$ 2,918	$ 8,402	$ 8,402
Trade and other receivables	2	$ 17,429	$ 17,429	$ 17,552	$ 17,552
Deposits	2	$ 427	$ 427	$ 413	$ 413
Financial liabilities at fair value through profit or loss:					
Risk management assets	2	$ 20,628	$ 20,628	$ –	$ –
Financial liabilities					
Financial liabilities at amortized cost:					
Accounts payable and accrued liabilities	2	$ 61,036	$ 61,036	$ 37,895	$ 37,895
Long-term debt	2	$ 29,000	$ 29,000	$ –	$ –

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).

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

(b) Risks associated with financial instruments

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

(i) Credit Risk

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

The Company's trade receivables are primarily with oil and gas marketers, the Alberta government and joint venture partners. Receivables from oil and gas marketers are generally collected on the 25th day of the month following production. The Company attempts to mitigate this risk by assessing the financial strength of its counterparties and entering into relationships with larger purchasers with established credit history. During 2014, the Company did not experience any collection issues with its marketers. At December 31, 2014, over 66 percent of total accounts receivable are for crude oil sales revenue (2013 – 78 percent).

In 2014, the Company had five customers (2013 – four) which individually accounted for more than 10 percent of its total oil and gas sales. Oil and gas sales to these customers represented approximately 73% of the Company's total oil and gas sales in 2014 (2013 – 65%).

At December 31, 2014, the Company had a $1.0 million (2013 – $4.1 million) receivable related to the reimbursement of crown royalties as a result of an enhanced oil recovery incentive program from the Alberta government. These amounts are not considered impaired based on the credit worthiness of the Alberta government and the approval the Company has received on its enhanced oil recovery activities.

Risk management assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. At December 31, 2014, the Company had a $4.0 million (2013 – $Nil) receivable related to the risk management contracts. During 2014, the Company did not experience any collection issues with its risk management contracts.

Receivables from joint venture partners arise when the Company conducts joint operations on behalf of its partners and invoices them for their share of costs. At December 31, 2014, the amount receivable from joint venture partners was $309,000 (2013 – $305,000). To mitigate the risk of non-payment from joint venture partners the Company can require partners to pay certain costs in advance as well as the Company has the ability to withhold production from partners in the event of non-payment. As at December 31, 2014, accounts receivable includes an allowance for doubtful accounts of $285,000 (2013 – $285,000) from joint interest partners. The majority of the Company's current operations do not have joint interest partners and therefore the credit risk from this group is considered low.

The Company typically does not obtain collateral or security from its joint venture partners or oil and gas marketers. The carrying amounts of accounts receivable represent the maximum credit exposure.

As at December 31, 2014, the Company held $2.9 million (2013 – $8.4 million) in cash at various major financial institutions throughout Canada and the USA. At December 31, 2014, one Canadian financial institution held over 64% (2013 – 88%) of our cash and short-term deposits.

(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 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, 2014, the Company had $121 million available on its credit facilities. Management believes that these sources will be adequate to settle the Company's financial liabilities and commitments.

The maturity dates for the Company's undiscounted cash outflows related to financial liabilities are as follows:

	<6 Months	6 months -1 Year	1-2 Years
Accounts payable and accrued liabilities	$ 61,039	–	–
Long-term debt	–	–	$ 29,000

(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 revolving credit facility due to the floating interest rate charged on advances. For the year ended December 31, 2014, if interest rates had been 1 percent higher with all other variables held constant, after tax net income for the year would have been approximately $12,000 (2013 – $Nil) lower. In addition, the Company is exposed to interest rate risk on its excess cash balances. As at December 31, 2014, if interest rates had been 1 percent higher with all other variables held constant, after tax net income for the year would have been approximately $71,000 (2013 – $21,000) higher.

(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) prices received for its crude oil are primarily determined in reference to U.S. dollars; (ii) certain expenditure commitments, deposits, accounts receivable, and accounts payable which are denominated in U.S. dollars; and to a lesser extent (iii) its operations in the United States. The Company manages this risk by monitoring foreign exchange rates and evaluating their effects on using Canadian or U.S. vendors as well as timing of transactions. As at December 31, 2014, the Company has not entered into any fixed rate contracts to mitigate its currency risks.

As at December 31, 2014, the Company held US $1.0 million (2013 – US $1.1 million) cash and cash equivalents, US $32,000 (2013 – $122,000) prepaid expenses and deposits and US $35,000 (2013 – US $126,000) accounts payable and accrued liabilities.

As at December 31, 2014, 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 income for the year would have been approximately $89,000 lower (2013 – $111,000 lower). An equal opposite impact would have occurred to net income had exchange rates been $0.10 higher.

(v) Commodity price risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Company's control. Changes in crude oil prices may significantly affect the Company's results of operations, cash generated from operating activities, capital spending and the Company's ability to meet its obligations. The majority of the Company's production is sold under short-term contracts; consequently BlackPearl is at risk to near term price movements. The Company manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program. Natural gas currently represents less than 5% (2013 – 3%) 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 at December 31, 2014, if our average oil wellhead sales price decreased $1.00 with all other variables held constant including risk management contracts, after tax net income for the year would have been approximately $2.5 million lower (2013 – $2.7 million lower). An equal opposite impact would have occurred to net income had average oil wellhead sales price been $1.00 higher.

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.

Risk management amounts recognized during 2014 were as follows:

	Year ended December 31, 2014	Year ended December 31, 2013
Realized gain on risk management contracts	$ 1,870	$ –
Unrealized gain on risk management contracts	20,628	–
Gain on risk management contracts	$ 22,498	$ –

The table below summarizes the Company's commodity contracts as at December 31, 2014:

Subject of Contract	Volume	Term	Reference	Strike Price	Option Traded
Oil	1,500 bbls/d	January 1, 2015 to March 31, 2015	CDN$ WCS	CDN$ 80.20/bbl	Swap
Oil	2,500 bbls/d	January 1, 2015 to June 30, 2015	CDN$ WCS	CDN$ 80.00/bbl	Swap

As at December 31, 2014, a 10% decrease in the CDN$ WCS forward benchmark price used to calculate unrealized gains for the risk management contracts above would result in a $2.6 million increase in after tax net income.

The table below summarizes commodity contracts the Company has entered into subsequent to December 31, 2014:

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

(1) The Company sold a European call option to a counterparty whereby the counterparty can elect on December 31, 2015 to exercise the option to enter into the oil swap.

(c) Capital Management

The Company's capital structure consists of working capital, long-term debt and shareholders' equity. The current capital management strategy is designed so that anticipated cash flow from operating activities combined with the existing credit facilities will fund continued development of our existing operations. At December 31, 2014, the Company had $29 million (2013 – $Nil) drawn under its existing credit facilities and issued letters of credit in the amount of $20,000 (2013 – $20,000); leaving $121 million (2013 – $115 million) available to be drawn under these credit facilities. Additional funding will 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 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. We would 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. At December 31, 2014, this ratio was 0.3 (2013 – 0.0). 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 in the Company.

19. SUPPLEMENTARY INFORMATION

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

	Year ended December 31, 2014	Year ended December 31, 2013
Cash interest paid	$ 1,140	$ 1,069
Cash taxes paid	$ 118	$ 71

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

	Year ended December 31, 2014	Year ended December 31, 2013
Gross interest and financing charges	$ 1,140	$ 1,069
Capitalized interest and financing charges	(634)	(226)
Net interest and financing charges	506	843
Accretion of decommissioning liabilities	1,532	1,094
Debt financing costs	–	1,012
Finance costs	$ 2,038	$ 2,949

(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, 2014	Year ended December 31, 2013
Changes in non-cash working capital:		
Trade and other receivables	$ 3,006	$ (4,916)
Inventory	(638)	–
Prepaid expenses and deposits	(37)	$ (85)
Accounts payable and accrued liabilities	23,313	(4,442)
	$ 25,644	$ (9,443)
Relating to:		
Operating activities	$ (10,372)	$ (4,659)
Investing activities	36,016	(4,784)
Changes in non-cash working capital	$ 25,644	$ (9,443)