PETROCAPITA INCOME TRUST

FORM 2A – LISTING STATEMENT
(Canadian Securities Exchange)

November 5, 2015

Notice to Reader: This Listing Statement relates to an application to list the common trust units of Petrocapita Income Trust on the Canadian Securities Exchange (CSE), and is based on the disclosure contained in the non-offering prospectus of the Trust dated October 26, 2015. It is comprised of (i) a Table of Concordance providing cross-references between the various items of CSE Form 2A and the portions of the prospectus containing disclosure relating to those items, (ii) the prospectus, (iii) the information required by Item 14 of CSE Form 2A, and (iv) a certificate of the Trust.

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(attached)

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This prospectus does not constitute a public offering of securities.

PROSPECTUS

Non-Offering Prospectus October 26, 2015

PETROCAPITA INCOME TRUST

No securities are being offered or sold pursuant to this prospectus.

This prospectus is being filed with the securities regulatory authority in the Province of Alberta to enable Petrocapita Income Trust (the "**Trust**" and, together with its subsidiaries, "**Petrocapita**") to become a reporting issuer under Alberta securities legislation. Since no securities are being sold pursuant to this prospectus, no proceeds will be raised. Expenses in connection with the preparation and filing of this prospectus will be borne by Petrocapita from its working capital.

The Trust is an unincorporated investment trust and qualifies as a "mutual fund trust" pursuant to the *Income Tax Act* (Canada) (the "**Tax Act**"). The Trust owns all of the outstanding limited partnership units of Petrocapita Oil and Gas L.P. (the "**Partnership**"), a limited partnership formed under the laws of the Province of Alberta, which holds all of Petrocapita's operating assets and is the party through which all of Petrocapita's active business operations are conducted. Petrocapita GP I Ltd. (the "**Corporation**"), a wholly-owned subsidiary of the Trust, is the administrator of the Trust and general partner of the Partnership. It is a corporation incorporated under the laws of the Province of Alberta. See "*The Trust and its Subsidiaries*".

The Trust is an Alberta-based exploration and operating oil and gas trust with heavy oil and produced water disposal wells in the Lloydminster area of Alberta and Saskatchewan.

The Trust is currently authorized to issue two classes of equity securities – being common units ("Trust Units") and preferred units, of which 1,109,731,962 Trust Units and no preferred units are currently issued and outstanding.

The Trust Units are equity securities and, like common shares of a corporate issuer, their market value will depend, in part, on the market's assessment of the intrinsic value of Petrocapita's assets and undertaking and ability to generate returns on an investment in Trust Units. **A return on an investment in Trust Units is not comparable to the return on an investment in a fixed-income security.** The recovery of any initial investment in Trust Units is at risk, and the anticipated return on the investment is based on many performance assumptions. **The Trust may in the future make distributions of available funds to holders of Trust Units, but has no obligation to do so.** Any distributions are discretionary, and will be determined by the trustees of the Trust based on its financial position at the relevant time (which will in turn depend on Petrocapita's earnings and obligations as well as decisions regarding reinvestment in its oil and gas operations and business). **In the near term, Petrocapita does not anticipate making cash distributions but instead reinvesting available cash flows in its business. Distributions may also be variable, and if made will be subject to reduction or suspension at any time. The Trust does not currently have any cash distribution targets in respect of the Trust Units.** If any such targets are established in the future, the market value of the Trust Units may decline if the Trust thereafter becomes unable to meet those targets, and that decline may be significant. **There is no assurance that cash distributions will be declared on a regular or consistent basis, or at all.** See "*Distribution Policy*".

Petrocapita owns and operates oil and gas properties. It is important that investors carefully consider the particular risk factors that may affect the industry in which they are investing, and therefore the stability of income generating capabilities and potential for cash distributions. See "*Risk Factors*".

The after-tax return from an investment in Trust Units to Unitholders subject to Canadian income tax will depend, in part, on the status of the Trust for purposes of the *Income Tax Act* (Canada), and the composition for income tax purposes of any distributions paid on the Trust Units (if any), portions of which may be fully or partially taxable as returns on capital (which are generally taxed as ordinary income or as dividends in the hands of a Unitholder) or may constitute tax deferred returns of capital (*i.e.*, returns that initially are nontaxable to a Unitholder but which reduce the Unitholder's adjusted cost base of the Trust Units held). To the extent of returns based on distributions, that composition may change over time, and any such changes may affect an investor's after-tax return. See "*Taxation of Specified Investment Flow-Through Trusts*".

An investment in and ownership of securities of the Trust should be considered speculative due to the nature of the Trust's involvement in the exploration for, and the acquisition, development and production of oil and natural gas reserves. Petrocapita's business is subject to the risks normally encountered in the oil and gas industry. Prospective purchasers of the Trust's securities must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Administrator. There is currently no market through which any securities of the Trust may be sold, and holders may not be able to resell securities of the Trust previously acquired by them. This may affect the pricing of the Trust's securities in the secondary market, the transparency and availability of trading prices, the liquidity of the Trust's securities and the extent of issuer regulation. See "*Risk Factors*" and "*Securities of the Trust – Market for Trust Securities*".

The head office of the Trust, the Partnership and the Corporation is located at #2210, 8561 - 8A Avenue S.W., Calgary, Alberta T3H 0V5. The registered office of the Corporation is located at #803, 5920 Macleod Trail S.W., Calgary, Alberta T2H 0K2.

No underwriter has been involved in the preparation of this prospectus or performed any review of the contents of this prospectus.

This prospectus does not constitute an offer to sell or the solicitation of an offer to buy any securities in any jurisdiction.

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PROSPECTUS SUMMARY

The following is a summary of the principal features of this prospectus and is qualified by and should be read in conjunction with the more detailed information, reserve data, financial data and statements appearing elsewhere in this prospectus. Capitalized terms used herein shall have the meaning ascribed thereto under the heading "Glossary" and "Notice to Investors – Unit Abbreviations".

Issuer	Petrocapita Income Trust
Administrator	Petrocapita GP I Ltd.
Business and Principal Properties	The Trust is an Alberta-based oil and gas exploration and production trust focused on the acquisition and development of heavy oil and water disposal wells in the Lloydminster area of Alberta and Saskatchewan. See "*Description of the Business*". Petrocapita's principal properties are located in 10 fields in two regions in the Lloydminster area of operations: the Lloydminster field in Alberta and nine fields in Saskatchewan (comprised of the Dee Valley, Dulwich, Edam East, Edam West, Landrose, Lashburn, Maidstone, Northminster and Turtleford fields). See "*Principal Properties*".
Outstanding Equity Securities	The Trust is currently authorized to issue two classes of equity securities – being Trust Units and Preferred Units, of which 1,109,731,962 Trust Units and no Preferred Units are currently issued and outstanding. See "*Securities of the Trust – Equity Securities*". Prior to June 21, 2015 there were approximately 33.8 million Preferred Units outstanding. On May 22, 2015, the Trust issued a notice of conversion to the holders of the outstanding Preferred Units pursuant to which, in accordance with the Declaration of Trust, all outstanding Preferred Units were converted to Trust Units effective June 21, 2015 on the basis of approximately 32.6 Trust Units for every one (1) Preferred Unit. See "*Declaration of Trust – Conversion of Preferred Units to Trust Units*". As a consequence of that conversion, there are no Preferred Units left outstanding and the former holders of Preferred Units (as a group) hold approximately 99.5% of the outstanding Trust Units.
Trustees of the Trust	The Trustees will be appointed at each annual meeting of Unitholders by Ordinary Resolution, to hold office for a term expiring at the close of the next annual meeting of Unitholders or until successors are duly elected or appointed, or their earlier death, resignation or removal in accordance with the Declaration of Trust. Trustees may be removed at any time by Ordinary Resolution. If a Trustee resigns, a majority of the Trustees remaining in office may appoint an individual as a replacement Trustee (and if they fail to do so then the Administrator may appoint such replacement). The current Trustees are Alex Lemmens, Greg Marr, Ben Van Rootselaar and Richard Mellis. See "*Trustees, Directors and Executive Officers*".
Administration of the Trust	In accordance with the provisions of the Declaration of Trust, and pursuant to the terms and conditions of the Administration Agreement, the Trust and the Trustees appointed the Administrator as administrator of the Trust, and delegated to the Administrator responsibility for the general administration, management and

governance of the affairs of the Trust, and in connection therewith the Administrator is required to provide and perform all administrative, management and governance services (with limited exceptions) as may be required or advisable from time to time in order to administer, manage and govern the operations of the Trust, including the services described below under the heading "*Administration Agreement*".

The Administration Agreement sets forth all of the rights, restrictions and limitations (including, without limitation, limitations of liability and indemnification rights) pertaining to the performance by the Administrator of the duties delegated to it by the Trustees. See "*Administration Agreement*".

Directors and Executive Officers of the Administrator

Each of the current Trustees is also a member of the Board of Directors.

The current directors and executive officers of the Administrator are:

- Alex Lemmens – President and Chief Executive Officer, and Chairman of the Board
- Evelyn Studer – Vice President, Finance and Chief Financial Officer
- Richard Mellis – Vice President, Land and Environment and a Director
- Greg Marr – Independent Director
- Ben Van Rootselaar – Independent Director

See "*Trustees, Directors and Executive Officers*".

Summary Reserves Information

The following table summarizes Petrocapita's estimated reserves as at December 31, 2014, as contained in the Reserves Report.

	HEAVY OIL	
Reserves Category[(1)(2)]	**Gross (Mbbls)**	**Net (Mbbls)**
PROVED		
Developed Producing	638	583
Developed Non-Producing	105	97
Undeveloped	127	116
TOTAL PROVED	869	795
PROBABLE		
Developed Producing	480	422
Developed Non-Producing	126	112
Undeveloped	813	700
TOTAL PROBABLE	1,418	1,234
TOTAL PROVED PLUS PROBABLE	2,287	2,029

Selected Financial and Operating Information

Financial years ended December 31, 2014, 2013 and 2012

The following table presents selected historical consolidated financial and operating information of the Trust at the dates and for the annual periods indicated. The figures given below should be read in conjunction with the audited consolidated financial statements of the Trust for the financial years ended December 31, 2014, 2013 and 2012, respectively, attached as Appendix A, and the related management's discussion and analysis for the financial years ended December 31, 2014 and 2013, respectively, attached as Appendix B.

	Year Ended December 31		
	2014	**2013**	**2012**
Financial ($000s)			
Oil sales [1]	10,344	8,772	4,406
Funds flow from operations [2]	2,254	1,738	631
Net income (loss)	(3,937)	(3,714)	(4.375)
Total long term assets	27,845	27,548	15,571
Total assets	31,365	32,988	31,274
Total financial liabilities	37,623	35,422	30,091
Net debt (surplus) [2]	(573)	(3,748)	(14,805)
Operating			
Oil Production (bbls/d)	374	365	187
Average realized price			
Oil revenue ($/bbl)	73.33	65.79	64.37
Water disposal revenue ($/bbl)	2.45	0.08	–
Operating netback			
Royalties ($/bbl)	(12.64)	(9.58)	(9.52)
Production expense ($/bbl)	(37.94)	(34.55)	(34.76)
Transportation expense ($/bbl)	(3.40)	(3.38)	(2.78)
Operating netback ($/bbl) [2]	21.80	18.36	17.31
General and administrative expense ($/bbl)	(5.20)	(5.31)	(8.10)
Funds flow netback ($/bbl)	16.60	13.05	9.21

Notes:

(1) Includes oil revenue, skim oil revenue and oil royalty revenue.
(2) See "*Notice to Investors – Non-IFRS Measures*".

Interim periods ended June 30, 2015 and 2014

The following table presents selected historical consolidated financial and operating information of the Trust at the dates and for the interim periods indicated. The figures given below should be read in conjunction with the consolidated financial statements of the Trust for the three and six month periods ended June 30, 2015 and 2014, attached as Appendix A, and the related management's discussion and analysis for the three and six month periods ended June 30, 2015, attached as Appendix B.

	Six Months Ended June 30	
	2015	**2014**
Financial ($000s)		
Oil sales [1]	1,883	5,626
Funds flow from operations [2]	(52)	1,404
Net income (loss)	(1,234)	(1,394)
Total long term assets	31,705	27,940
Total assets	33,647	33,295
Total financial liabilities	10,672	37,070
Net debt (surplus) [2]	(169)	(3,238)
Operating		
Oil Production (bbls/d)	255	404
Average realized price		
Oil revenue ($/bbl)	40.77	76.87
Water disposal revenue ($/bbl)	0.82	1.84
Operating netback		
Royalties ($/bbl)	(3.94)	(13.23)
Production expense ($/bbl)	(27.22)	(37.91)
Transportation expense ($/bbl)	(2.14)	(3.72)
Operating netback ($/bbl) [2]	8.29	23.85
General and administrative expense ($/bbl)	(9.42)	(4.69)
Funds flow netback ($/bbl)	(1.13)	19.16

Notes:

(1) Includes oil revenue, skim oil revenue and oil royalty revenue.
(2) See "*Notice to Investors – Non-IFRS Measures*".

Risk Factors

An investment in the Trust Units involves a substantial degree of risk and is highly speculative due to the nature of Petrocapita's business and the risks inherent in the oil and gas industry in which Petrocapita operates. As a result, investors should only consider investing in the Trust Units if they can afford to lose their entire investment.

Risks related to Petrocapita's production, development and exploration operations include: (i) declines in oil and gas commodity prices; (ii) failure or delays in obtaining required regulatory approvals and other authorizations; (iii) adverse changes in royalty regimes; (iv) abandonment and reclamation costs; and (v) increased deposit requirements or other adverse changes under applicable liability management programs.

Risks related to Petrocapita's business, financial matters and tax matters include: (i) geopolitical risks insofar as they impact commodity prices; (ii) inability to secure additional financing on acceptable terms; (iii) variations in foreign exchange rates and interest rates; and (iv) reliance on management and key personnel.

Risks related to an investment in Trust Units include: (i) the absence of a prior market for the Trust Units; and (ii) price volatility.

These and other risk factors are discussed in greater detail under "*Risk Factors*" below, are not an exhaustive list of all risks associated with an investment in the Trust Units, and should be read in conjunction with all other information contained in this prospectus. See "*Risk Factors*".

GLOSSARY

In this prospectus, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below:

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**Administration Agreement**" means the administration agreement made as of January 22, 2010 between the Administrator and the Trust, as amended, supplemented or amended and restated from time to time;

"**Administrator**" means the Corporation, and any successor or permitted assign thereof, in its capacity as administrator of the Trust; provided that where there is no person acting as administrator of the Trust then the Trustees shall be responsible for all matters in connection with the administration and operation of the Trust, including all matters referred to in this Declaration of Trust as being duties, responsibilities or obligations of the Administrator;

"**API**" means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter than and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**Audit Committee**" means the audit committee of the Trust;

"**Board**" or "**Board of Directors**" means the board of directors of the Administrator;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**Corporation**" means Petrocapita GP I Ltd., a corporation formed under the laws of the Province of Alberta;

"**Declaration of Trust**" means the declaration of trust governing the Trust originally made as of January 22, 2010, as amended and restated as of October 1, 2010 and further amended and restated as of October 26, 2015, among the trustees, the Administrator, the settlor of the Trust, and each person who is or becomes a Unitholder, as further amended, supplemented or amended and restated from time to time;

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

"**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty;

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing;

"**development cost**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building

and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

"**development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive;

"**DRIP**" means the distribution re-investment program of the Trust pursuant to which holders of Preferred Units may reinvest cash distributions from the Trust in additional Preferred Units;

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well;

"**field**" means a defined geographical area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations;

"**finding, development and acquisition costs**" means the identified capital expenditures associated with the addition of proved plus probable reserves including changes in future development capital, divided by the associated reserve additions during the period that the expenditures were incurred;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Petrocapita is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a);

"**General Partner**" means the Corporation, and any successor or permitted assign thereof, in its capacity as general partner of the Partnership;

"**gross**" means:

(a) in relation to a company's interest in production or reserves, its "company gross reserves", which are the company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the company;

(b) in relation to wells, the total number of wells in which a company has an interest; and

(c) in relation to properties, the total area of properties in which a company has an interest;

"**horizontal drilling**" means a drilling technique used in certain formations where a well is drilled vertically to a certain depth, after which the drill path builds to 90 degrees until it is in the target formation and continues horizontally for a certain distance;

"**IFRS**" means the International Financial Reporting Standards as adopted by the International Accounting Standards Board;

"**Limited Partner**" means the Trust and each of those persons from time to time admitted to the Partnership as additional limited partners in accordance with the terms of the LP Agreement;

"**LP Agreement**" means the limited partnership agreement governing the Partnership made as of January 22, 2010 among the General Partner, as general partner, the Trust, as the founding limited partner, and such other persons who become Limited Partners in accordance with the terms of such agreement, as amended, supplemented or amended and restated from time to time;

"**LP Units**" means the "units" in the Partnership, as defined pursuant to the LP Agreement;

"**NEB**" means the National Energy Board of Canada;

"**net**" means:

(a) in relation to a company's interest in production and reserves, the company's interest (operating and non-operating) share after deduction of royalty obligations, plus the company's royalty interest in production or reserves;

(b) in relation to a company's interest in wells, the number of wells obtained by aggregating the company's working interest in each of its gross wells; and

(c) in relation to a company's interest in a property, the total area in which the company has an interest multiplied by the working interest owned by the company.

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees* of the Canadian Securities Administrators;

"**Ordinary Resolution**" means (i) a resolution passed by more than 50% of the votes cast by those Unitholders entitled to vote on such resolution, whether cast in person or by proxy, at a meeting of Unitholders, at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or (ii) a resolution approved in writing, in one or more counterparts, by holders of more than 50% of the votes represented by those Trust Units entitled to be voted on such resolution;

"**Partnership**" means Petrocapita Oil and Gas L.P., a limited partnership formed under the Partnership Act;

"**Partnership Act**" means the *Partnership Act* (Alberta), R.S.A. 2000, c P-3, as amended, including the regulations promulgated thereunder;

"**Petrocapita**" means, collectively, the Trust and its subsidiary entities, including the Partnership and the Corporation;

"**Preferred Unit**" means a preferred unit of beneficial interest in the Trust issued from time to time in accordance with the Declaration of Trust and having the rights, privileges, restrictions and conditions set out in the Declaration of Trust, and a "**holder of Preferred Units**" means a person whose name appears on the register of the Trust as a holder of Preferred Units;

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves;

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**Reserves Report**" means the reserves evaluation report dated July 17, 2015 prepared by Chapman Petroleum Engineering Ltd., Petrocapita's independent qualified reserves evaluator, evaluating the reserves of Petrocapita as of December 31, 2014;

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"**reservoir**" means a porous and permeable underground rock formation containing a natural accumulation of petroleum that is confined by impermeable rock or water barriers, is separate from other reservoirs and is characterized by a single pressure system;

"**SIFT trust**" means a trust that is a "specified investment flow-through" trust for purposes of the Tax Act;

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion;

"**Special Resolution**" means (i) a resolution passed by more than 66⅔% of the votes cast by those Unitholders entitled to vote on such resolution, whether cast in person or by proxy, at a meeting of Unitholders, at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or (ii) a resolution approved in writing, in one or more counterparts, by holders of more than 66⅔% of the votes represented by those Trust Units entitled to be voted on such resolution;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c-1 (5th Supp.), as amended, including the regulations promulgated thereunder;

"**Trust**" means Petrocapita Income Trust, an unincorporated investment trust formed under and governed by the laws of the Province of Alberta;

"**Trustees**" means those individuals who are trustees of the Trust from time to time on the terms provided for in the Declaration of Trust; and "**Trustee**" means any one of them;

"**Trust Unit**" means a common unit of beneficial interest in the Trust issued from time to time in accordance with the Declaration of Trust and having the rights, privileges, restrictions and conditions set out in the Declaration of Trust, and a "**holder of Trust Units**" means a person whose name appears on the register of the Trust as a holder of Trust Units;

"**U.S.** or **United States**" means the United States of America, its territories and possessions, any state of the United States and the District of Columbia;

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned;

"**Units**" means the Trust Units or Preferred Units, as the case may be, and references in this Prospectus to Units shall mean a reference to Trust Units and/or Preferred Units, as the context so requires; and "**Unit**" means one Trust Unit or Preferred Unit, as the case may be;

"**Unitholder**" means a person whose name appears on the register of the Trust as a holder of one or more Trust Units or Preferred Units; and

"**working interest**" means the right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

NOTICE TO INVESTORS

About this Prospectus

Prospective investors should rely only on the information contained in this prospectus and should not rely on any other information when making a decision to invest in Petrocapita. The Trust has not authorized any other person to provide information other than that which is contained in this prospectus. If you are provided with additional or different information, or information that is inconsistent with the information given in this prospectus, you should not rely on it.

The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time this prospectus is delivered to you. Petrocapita's business, financial condition, results of operations, cash flows and future prospects may have changed since the date of this prospectus.

This prospectus is not an offer to sell or a solicitation of an offer to buy securities in any jurisdiction.

References to "Management" in this prospectus means the executive officers of the Administrator. Any statements in this prospectus made by or on behalf of management are made in such persons' capacities as officers of the Administrator and not in their personal capacities.

Unless otherwise indicated, references to "CDN$" or "$" are to Canadian dollars and references to "US$" are to U.S. dollars. Unless otherwise indicated, all financial information relating to Petrocapita in this prospectus is presented in Canadian dollars using IFRS.

Non-IFRS Measures

In addition to using financial measures prescribed by IFRS, references are made in this prospectus to "operating netback", "operating cash flow", "adjusted EBITDA", "net debt", "funds flow from operations" and "funds flow netback", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the financial statements of Petrocapita. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities. Management uses such terms in the evaluation of Petrocapita 's operating and financial performance and to provide Unitholders with a measurement of Petrocapita's efficiency and its ability to generate the cash necessary to fund its capital expenditures, repay debt or pay distributions.

"***Operating income (loss)***" is calculated as total petroleum, natural gas and water disposal sales (excluding realized and unrealized gains and losses on commodity risk management contracts) less royalties and production and transportation expenses for the period. Management uses operating income (loss) as an indicator of operating performance and profitability. There are no IFRS measures that are reasonably comparable to operating income.

"***Operating netback***" is calculated as operating income divided by barrels of oil production volume for the period. Management uses operating netback as an indicator of operating performance and profitability relative to current commodity prices, calculated on a per barrel basis. There are no IFRS measures that are reasonably comparable to operating netback.

"***Funds flow netback***" is calculated as operating netback less general and administrative expenses (on a per barrel basis). By starting with operating netback and further deducting general and administrative (but not financing) costs, Management uses funds flow netback as a supplemental indicator of operational profitability. There are no IFRS measures that are reasonably comparable to funds flow netback.

"***Operating cash flow***" is calculated as total petroleum, natural gas and water disposal revenue, excluding realized and unrealized gains and losses on commodity risk management contracts, less royalties, production and transportation expenses, exploration and evaluation expenses and general and administrative expenses.

Management uses operating cash flow as a means of assessing the Trust's operating performance and cash availability. There are no IFRS measures that are reasonably comparable to operating cash flow.

"***Adjusted EBITDA***" is calculated as earnings before financing expenses, provision for deferred income tax or recovery, depletion and depreciation, impairments, unrealized gains or losses on risk management contracts, unrealized gains or losses on foreign exchange on long-term debt and gains or losses on acquisitions and dispositions. Adjusted EBITDA is used to assess the performance of Petrocapita's operations prior to financing expenses, without the effects of depletion and depreciation, other non-cash items and other non-recurring events.

"***Net debt***" is calculated as current liabilities plus indebtedness under outstanding debentures less current assets (excluding the fair value of risk management contracts) and is used by Management to assess liquidity and general financial strength. Net debt should not be considered an alternative to, or more meaningful than, current assets or current liabilities, as determined in accordance with IFRS.

"***Funds flow from operations***" is calculated as cash flow from operating activities, as determined in accordance with IFRS, adjusted for cash paid financing costs, changes in non-cash working capital and decommissioning obligations expenditures. Management considers funds flow from operations a key measure as it demonstrates Petrocapita's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt. Funds flow from operations does not have any standardized meaning prescribed by IFRS and Management's calculation of funds flow from operations may not be comparable to that reported by other entities.

Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. Funds flow from operations per bbl is calculated using boe production volume for the period. Funds flow from operations per unit is calculated using the weighted average units (basic and diluted) used in calculating net income (loss) per unit on a basic and diluted basis.

A reconciliation of cash flow from operating activities and funds flow from operations is as follows:

	($000s)		
	Year Ended December 31		
	2014	**2013**	**2012**
Cash flow from operating activities – IFRS	1,991	2,137	1,159
Changes in non-cash operating working capital	302	(302)	(464)
Decommissioning costs incurred	0	0	0
Cash paid financing expenses	(39)	(97)	(64)
Funds flow from operations	2,254	1,738	631

Exchange Rate Data

The following table sets forth, for each of the periods indicated, the average and period-end noon spot rates of exchange for US$1.00, as reported by the Bank of Canada and expressed in Canadian dollars.

	Year Ended December 31		
	2014 (CDN$/US$)	**2013** (CDN$/US$)	**2012** (CDN$/US$)
Average noon spot rate during period [(1)]	1.1045	1.0299	0.9996
End of period noon spot rate	1.1601	1.0636	0.9949

Note:

(1) Determined by averaging the noon spot rates on each business day during the respective period.

On October 26, 2015, the Bank of Canada noon rate for conversion of Canadian dollars into U.S. dollars was US$1.00 = CDN$1.3134.

Market and Industry Data

This prospectus contains statistical data, market research and industry forecasts that were obtained from government or other industry publications and reports or based on estimates derived from such publications and reports and Management's knowledge of, and experience in, the markets in which Petrocapita operates. Government and industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but do not guarantee the accuracy and completeness of their information. None of the authors of such publications and reports has provided any form of consultation, advice or counsel regarding any aspect of, or is in any way whatsoever associated with, the preparation of this prospectus. Further, certain of these organizations are advisors to participants in the oil and gas industry, and they may present information in a manner that is more favourable to that industry than would be presented by an independent source. Actual outcomes may vary materially from those forecast in such reports or publications, and the prospect for material variation can be expected to increase as the length of the forecast period increases. While management believes this data to be reliable, market and industry data is subject to variations and cannot be verified due to limits on the availability and reliability of data inputs, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any market or other survey.

Note on Reserves Data

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The qualitative certainty levels referred to in the definitions set forth under the heading "*Glossary*" in this prospectus are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

In this prospectus:

(a) there is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of oil reserves provided in this prospectus are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil reserves may be greater than or less than the estimates provided in this prospectus;

(b) Petrocapita does not have any synthetic oil or other products from non-conventional oil and gas activities; and

(c) numbers may not add due to rounding.

The discounted and undiscounted net present value of future net revenues attributable to reserves do not represent the fair market value of such reserves.

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

Unit Abbreviations

bbl	barrel of oil	PV-10	Present value of reserves, discounted at 10%
bbls/d	barrels of oil per day	m	metre
Mbbls	thousand barrels of oil		

Conversions

To Convert From	To	Multiply By
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Mcf	Thousand cubic metres	0.028
Thousand cubic metres	Mcf	35.494
Bbl	Cubic metres	0.159
Cubic metres	bbl	6.29
Btu	Joules	1,055.05585
Joules	Btu	0.000947817
mPa-s	cP	1

FORWARD-LOOKING STATEMENTS

Certain statements and information contained in this prospectus constitute forward-looking statements and forward-looking information as defined under applicable securities legislation (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or Petrocapita's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this prospectus should not be unduly relied upon. These statements speak only as of the date of this prospectus. In addition, this prospectus may contain forward-looking statements attributed to third party industry sources.

In particular and without limitation, this prospectus contains forward-looking statements pertaining to the following:

- the reserve potential of Petrocapita's assets;
- the estimated production from Petrocapita's assets;
- the estimated quantity and value of Petrocapita's proved and probable reserves;
- Petrocapita's plans to continue with its heavy oil and water disposal based focus;
- Petrocapita's growth strategy of growing organically and through accretive acquisitions;
- expectations with respect to future growth, opportunities and stability;
- expectations regarding commodity prices and costs;
- Petrocapita's capital expenditure program and future capital requirements;
- Petrocapita's estimates of future interest and foreign exchange rates;
- expectations regarding taxability of the Trust;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil and natural gas;
- Petrocapita's access to adequate pipeline capacity;
- Petrocapita's access to third-party infrastructure;
- industry conditions pertaining to the oil and gas industry;
- Petrocapita's plans for exploration and development activities
- Petrocapita's abandonment and reclamation cost expectations;
- Petrocapita's treatment under governmental regulatory regimes and tax laws;
- Petrocapita's access to capital and overall strategy, development and drilling plans for all of Petrocapita's assets; and
- expectations on how Petrocapita will manage exploration, production and marketing risks.

With respect to forward-looking statements contained in this prospectus, assumptions have been made regarding, among other things, the following:

- future crude oil, natural gas liquids and natural gas prices;
- Petrocapita's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which Petrocapita conducts its business and any other jurisdictions in which Petrocapita may conduct its business in the future;
- Petrocapita's ability to market production of oil and gas successfully to customers;
- Petrocapita's future production levels;
- the applicability of technologies for recovery and production of Petrocapita's reserves;
- the recoverability of Petrocapita's reserves;
- future cash flows from production meeting the expectations stated in this prospectus;
- geological and engineering estimates in respect of Petrocapita's reserves;
- the geography of the areas in which Petrocapita is conducting exploration and development activities;

- the impact of competition on Petrocapita; and
- Petrocapita's ability to obtain future financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this prospectus, including:

- business operations and capital costs;
- Petrocapita's status and stage of development and the management of growth;
- general economic, market and business conditions;
- volatility in market prices and demand for crude oil and natural gas and hedging activities related thereto;
- seasonality of the Canadian oil and gas industry;
- risks related to the exploration, development and production of oil and natural gas reserves;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates and stock market volatility;
- competition for, among other things, capital, the acquisition of reserves and skilled personnel;
- operational hazards;
- actions by governmental authorities, including changes in government regulation and taxation;
- environmental risks and hazards;
- risks inherent in the exploration, development and production of oil and natural gas which may create liability to Petrocapita in excess of its insurance coverage;
- cost of new technologies;
- failure to accurately estimate abandonment and reclamation costs;
- failure of third parties' reviews, reports and projections to be accurate;
- the availability of capital on acceptable terms;
- political risks;
- climate change;
- changes to royalty or tax regimes;
- the failure of the General Partner or the holders of certain licenses or leases to meet specific requirements of such licenses or leases;
- claims made in respect of Petrocapita's properties or assets;
- aboriginal claims;
- unforeseen title defects;
- risks arising from future acquisition activities;
- risks associated with the realization of anticipated benefits of acquisitions and dispositions;
- risks associated with the Trust's structure;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;
- risks associated with establishing and maintaining systems of internal controls;
- risks related to the reliance on historical financial information, including that historical financial information does not reflect the added costs that Petrocapita expects to incur as a public entity;
- liquidity and additional funding requirements;
- additional indebtedness;
- failure to engage or retain key personnel;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which Petrocapita is reliant;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- failure to acquire or develop replacement reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- disclosure of confidential information of Petrocapita; and
- other factors discussed under "*Risk Factors*".

In addition, information and statements in this prospectus relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See also "*Notice to Investors – Note on Reserves Data*".

There are numerous uncertainties inherent in estimating quantities of oil and natural gas and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this prospectus are estimates only. In general, estimates of economically recoverable oil and natural gas and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Petrocapita's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. See also "*Notice to Investors – Note on Reserves Data*".

The forward-looking statements included in this prospectus are expressly qualified by this cautionary statement and are made as of the date of this prospectus. Petrocapita does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

THE TRUST AND ITS SUBSIDIARIES

Petrocapita Income Trust is an unincorporated investment trust formed under the laws of the Province of Alberta pursuant to the Declaration of Trust on January 22, 2010. The Trust is the sole shareholder of the Corporation, and the Corporation (as General Partner) and the Trust are the only partners of the Partnership. See "*Declaration of Trust*".

Petrocapita Oil and Gas L.P. is a limited partnership formed under to the Partnership Act in the Province of Alberta on January 22, 2010 pursuant to the LP Agreement. The Partnership holds all of Petrocapita's oil and gas assets, and all of Petrocapita's active business operations are conducted through the Partnership. As at the date hereof, the Trust and the Corporation (as General Partner) are the only partners of the Partnership, with the Trust holding 100% of the outstanding LP Units. See "*Limited Partnership Agreement*".

Petrocapita GP I Ltd. is a corporation formed under the ABCA in the Province of Alberta on January 4, 2010. It is a wholly-owned subsidiary of the Trust and serves as administrator of the Trust and general partner of the Partnership. See "*Administration Agreement*" and "*Limited Partnership Agreement*".

The head office of the Trust, the Partnership and the Corporation is located at #2210, 8561 - 8A Avenue S.W., Calgary, Alberta T3H 0V5. The registered office of the Corporation is located at #803, 5920 Macleod Trail S.W., Calgary, Alberta T2H 0K2.

Operating Entities

Pursuant to National Policy 41-201– *Income Trusts and Other Indirect Offerings* of the Canadian Securities Administrators ("**NP 41-201**"), the operating entity of an income trust is considered to be a subsidiary of the income trust with an underlying business, or income-producing properties owned directly by the trust. In Petrocapita's circumstances, the Partnership would be the operating entity for the Trust.

The Trust has, concurrently with the filing of this prospectus, filed with the Alberta Securities Commission a written undertaking that in complying with its reporting issuer obligations, it will treat the operating entity (as that term is used in NP 41-201) of the Trust as a subsidiary of the Trust; provided, however, that if applicable accounting standards used by the Trust prohibit the consolidation of financial information of the Trust and the operating entity, then for as long as the operating entity (including any of its significant business interests) represents a significant asset of the Trust, the Trust will provide separate audited annual financial statements and interim financial reports, prepared in accordance with the same accounting standards as the Trust's financial statements, and related management's discussion and analysis, prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations* of the Canadian Securities Administrators or its successor, for the operating entity (including information about any of its significant business interests). The Trust will also be required to annually certify to the Alberta Securities Commission that it has complied with this undertaking, and file a copy of the certification on SEDAR concurrently with the filing of its annual financial statements.

DESCRIPTION OF THE BUSINESS

Business of the Trust

The Trust is an Alberta-based oil and gas exploration and production trust focused on the acquisition and development, through its subsidiary entities, of heavy oil and water disposal wells in the Lloydminster area of Alberta and Saskatchewan. Specifically, Petrocapita's principal properties are located in 10 fields in two regions in the Lloydminster area of operations: the Lloydminster field in Alberta and nine fields in Saskatchewan (comprised of the Dee Valley, Dulwich, Edam East, Edam West, Landrose, Lashburn, Maidstone, Northminster and Turtleford fields). See "*Principal Properties*" below.

Business Strategy and Objective

Petrocapita's strategy is to grow through low cost acquisitions and operations principally located in the Provinces of Alberta and Saskatchewan. Management intends to focus on accretive acquisitions and/or development transactions having production or production potential within the range of 15 - 300 boe/d.

Petrocapita's primary objective is to identify, evaluate and acquire oil and gas assets with opportunities to develop infrastructure (including water disposal wells, or interests therein) which can reliably generate income so as to provide a reasonable return to investors.

Management anticipates that a majority of the assets to be acquired from time to time (whether mineral interests, current or shut-in production, or other interests) will be in respect of heavy oil properties and related or ancillary assets. With respect to heavy oil assets, Management believes such assets have potential to provide significant upside while at the same time providing stable income generation. Significantly, such assets will typically require development of infrastructure to strictly manage cost and improve oil recovery. Such infrastructure will initially be in the form of converting lower return oil wells and facilities into produced water processing and disposal facilities but can expand to include produced water flowlines, fuel gas flowlines, fluid transportation equipment and facilities, drilling and well servicing equipment, and centralized oil processing facilities.

See also "*Operational Matters*" and "*Industry Conditions*" below.

GENERAL DEVELOPMENT OF THE BUSINESS

The business of Petrocapita commenced in 2010 following the formation of the Trust and the initial acquisition by Petrocapita in February 2010 of undeveloped land near Dulwich, Saskatchewan and other assets from an arm's length third party. The initial acquisition included five oil wells (5.0 net), 300 (300 net) acres of mineral rights and production equipment. During 2010 and 2011 Petrocapita acquired additional oil and gas properties, drilled a total of seven (6.5 net) heavy oil wells and re-completed twenty-one (21.0 net) heavy oil wells across its asset base.

For a description of Petrocapita's oil and gas properties acquired see "*Principal Properties*" below.

Following is a description of Petrocapita's business development over the past three completed financial years, since January 1, 2012. As at January 1, 2012, Petrocapita owned 540 acres of land (520 net), 13 wells (12.5 net) and had produced an average of 55.6 bbls/d for the year ended December 31, 2011 (52.5 bbls/d exit rate 2011).

2012

Effective May 1, 2012, Petrocapita purchased 160 acres of mineral land rights (160 net) and seven oil wells (7.0 net) near Lloydminster, Saskatchewan from an arm's length third party for aggregate consideration of $280,000 plus applicable taxes.

In 2012, Petrocapita spent an additional $7,584,607 developing and optimizing its properties by drilling seven oil wells (7.0 net), acquiring eight wells (8.0 net) as part of re-completing 17 oil wells (17.0 net) and earning and purchasing 2,043 acres of mineral land rights (2,043 net).

As at December 31, 2012, Petrocapita owned 2,743 acres of land (2,723 net), 28 wells (27.5 net) and produced an average of 187.3 bbls/d for the year ended December 31, 2012 (166.5 bbls/d exit 2012).

2013

On March 22, 2013, Petrocapita purchased a 100% working interest and operatorship of heavy oil assets in the Lloydminster area of Alberta from an arm's length third party, which included 1,905 acres of mineral land rights (1,783 net), 35 oil wells (34.3 net), production equipment, proprietary seismic data, and pipeline rights of way. The aggregate consideration for the acquired assets was $6,300,000 plus purchase price adjustments and applicable taxes.

On April 22, 2013, Petrocapita purchased a 33⅓% working interest and operatorship of heavy oil assets in Alberta and a 50% working interest and operatorship of heavy oil assets in the Landrose and Maidstone area in Saskatchewan from an arm's length third party, which included 1,872 acres of mineral land rights (852 net), 58 oil wells (28.3 net) and production equipment. The aggregate consideration for the acquired assets was $1,875,000 plus purchase price adjustments and applicable taxes.

In 2013, Petrocapita spent an additional $2,367,192 developing and optimizing its properties by re-completing 27 oil wells (27.0 net) and purchasing 320 acres of mineral land rights (320 net).

In November 2013, Petrocapita initiated a salt water disposal program to help lower its operating and transportation costs and create additional cash flow by disposing of third party produced water and recovering skim oil.

As at December 31, 2013, Petrocapita owned 6,920 acres of land (5,918 net), 121 wells (90.1 net), and produced an average of 383.3 bbls/d for the year ended 2013 (372.3 bbls/d exit 2013). In addition, Petrocapita's salt water disposal program processed approximately 60,650 barrels of fluid and produced approximately 22 barrels of skim oil in 2013.

2014

In 2014, Petrocapita drilled two oil wells (1.7 net), re-completed 12 oil wells (12.0 net) and purchased 80 acres of mineral land rights (40 net).

In 2014, Petrocapita generated income from salt water disposal of $933,000, of which $521,000 (up from $49,000 in 2013) was from salt water disposal and $412,000 (up from $8,000 in 2013) was from skim oil sales.

In light of declining oil prices in late 2014, Petrocapita temporarily shut in 20 wells and approximately 200 bbls/d of production, reduced capital spending on drilling and re-completion of wells, and increased its focus on further developing its water disposal program. As at December 31, 2014, Petrocapita had nine potential salt water disposal sites requiring limited capital to initiate disposal operations.

As at December 31, 2014, Petrocapita owned 6,685 acres of land (5,476 net), 123 wells (92.0 net), and produced an average of 379.3 bbls/d for the year end 2014 (371.1 bbls/d exit 2014). In addition, Petrocapita's salt water disposal program processed approximately 936,900 barrels of fluid and produced approximately 5,913 barrels of skim oil.

2015

Since the start of 2015, Petrocapita acquired a 100% interest in an operational salt water disposal facility and **seven** gross (7.0 net) oil wells in the Lloydminster area of Alberta; increased to 100% its working interest in 46 gross oil wells in which it previously held working interests of between 25% and 50% (increasing its net well count with respect to those 46 wells from 20.1 net wells to 46.0 net wells), and purchased one gross (1.0 net) additional oil well from the same vendor; acquired 11 gross (9.4 net) oil wells in Saskatchewan; and purchased six fluid haul trailers. The net consideration paid by Petrocapita in these transactions was approximately $870,000, which included settlement of outstanding joint interest billings and the issuance to two vendors of $677,000 aggregate principal amount of secured debentures, plus the transfer of substantially all of Petrocapita's interest in three gross (1.5 net) oil wells in the Lloydminster area and related land. See "*Securities of the Trust – Debt Securities*".

In June 2015 Petrocapita reactivated 11 of the wells that it had temporarily shut-in as at December 31, 2014, which restored approximately 100 bbls/d of production.

In light of the discounted pricing for heavy oil production and the high water cut experienced in the mature fields in which Petrocapita operates, Management continues to view the development of mature infrastructure – particularly with respect to salt water disposal, transportation and processing – and realization of associated operating costs savings as a means to competitive advantage in the heavy oil business. Petrocapita currently has four operating salt water disposal facilities (two in each of Alberta and Saskatchewan), with regulatory approvals received for three additional wells and applied for in respect of a further two wells.

As at June 30, 2015, Petrocapita owned 7,267 acres of land (6,145 net) and 141 wells (134.4 net), and produced an average of 301 bbls/d for the six month period ended June 30, 2015. In addition, Petrocapita's salt water disposal program processed approximately 298,000 barrels of fluid and produced approximately 597 barrels of skim oil for the six month period ended June 30, 2015.

PRINCIPAL PROPERTIES

General

Petrocapita's heavy oil assets are located in the Lloydminster area of Alberta and Saskatchewan and include up to nine potential producing horizons which form the clastic unit of the Lower Cretaceous age known as the Mannville group of oil bearing sands. The sands are generally found in a pro-grading deltaic environment but can be part of a shoreline to shallow marine environment. Oil from these pools is typical of the conventional higher viscosity Lloydminster Mannville pools (30,000 to 60,000 cp), but can exhibit lower viscosity heavy oil (18,000 to 30,000 cp) in certain pools, especially in the Colony, Sparky and Waseca horizons.

Petrocapita's properties are all located in well developed areas with extremely detailed well control and analog productivity profiles from many years of intensive drilling and production activity in their areas of focus. This data is extremely useful to Petrocapita in estimating reserves, and in the selection of drilling locations.

Petrocapita has developed a growth plan to organically increase production through a variety of opportunities including drilling its inventory of low-risk infill locations, expanding and optimizing infrastructure and implementing secondary and tertiary enhanced oil recovery techniques, such as high volume lift and steam injection.

High volume lift utilizes Petrocapita's inventory of salt water disposal locations to increase total production from high water cut wells owned by Petrocapita and third parties in order to increase total oil production and reduce the cost of disposal of produced water. Steam injection in certain reservoirs substantially increases recoveries and is being extensively tested by third parties in Petrocapita's operating area.

Petrocapita's production is derived from 10 fields in two regions in the Lloydminster area of operations: the Lloydminster field in Alberta and nine fields in Saskatchewan (comprised of the Dee Valley, Dulwich, Edam East, Edam West, Landrose, Lashburn, Maidstone, Northminster and Turtleford fields), descriptions of which are set forth below.

Lloydminster Region

The Lloydminster heavy oil region is centered around the City of Lloydminster on the Alberta/Saskatchewan border. It encompasses an area from Township 36 in the south to Township 57 in the north and from Range 17W3 to Range 8W4, east to west. This region's production is predominantly heavy oil in the 12º to 16º API range that comes from a variety of zones including the Colony, McLaren, Waseca, Sparky, General Petroleum, Rex, Lloydminster, Cummings and Dina at depths of 500 to 700 metres.

Petrocapita's properties in the Lloydminster field in Alberta exhibit production largely from the Sparky horizon but also have porosity in the Lloydminster and Dina horizons which usually have high salt water saturation and are more suitable for produced water disposal.

Petrocapita's properties in Saskatchewan generally exhibit oil pay in the Sparky, McLaren and Waseca formations, but also have porosity in the Lloydminster and Dina horizons which usually have high salt water saturation and are more suitable for produced water disposal.

Petrocapita holds approximately 2,123 gross (2,023 net) undeveloped acres in this region. Of the 16 gross wells (15.2 net) drilled by Petrocapita since its inception, all were drilled in this region and it is anticipated that nearly all of the wells to be drilled by Petrocapita in 2015 will be drilled in this region.

From the first heavy oil well brought on production in 2010, Petrocapita has acquired and drilled a total of 141 (134.4 net) heavy oil wells to June 30, 2015, with one well (0.5 net) drilled in 2010, six wells (6.0 net) drilled in

2011, seven wells (7.0 net) drilled in 2012, no wells drilled in 2013, two wells (1.7 net) drilled in 2014, and no wells drilled in the first half of 2015.

As at June 30, 2015, Petrocapita had 141 gross (134.4 net) oil wells, of which 32 gross (30.0 net) oil wells were on production and a further 109 gross (104.4 net) wells were standing waiting on improved economics from re-completion and water disposal.

Petrocapita's intended program for 2015 includes converting up to seven gross (7.0 net) existing suspended oil wells and producing facilities to produced salt water disposal batteries and a work-over and re-completion program focused on maximizing skim oil production and minimizing production cost in the Lloydminster heavy oil region. All of Petrocapita's production is gathered at single well or multi-well facilities of which it has ownership and control. Petrocapita has ownership in approximately 140 heavy oil batteries with capacity for approximately 105,000 bbls of fluid.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The estimates of Petrocapita's proved reserves and probable reserves and related future net revenue included in the statement of reserves data and other oil and natural gas information set forth below are based on the Reserves Report, which evaluated Petrocapita's reserves as at an effective date of December 31, 2014 using forecast prices and costs and has a preparation date of July 17, 2015. The Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2, and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3, are attached as Appendix D and Appendix E to this prospectus, respectively.

Disclosure of Reserves Data

The reserves data disclosed herein summarizes the estimated reserves of Petrocapita and net present values of estimated future net revenue related to the reserves using forecast prices and costs, not including the impact of any price risk management activities. The Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*. Petrocapita engaged Chapman Petroleum Engineering Ltd. to provide an evaluation of its proved reserves and its probable reserves.

Petrocapita determined the future net revenue and present value of future net revenue after income taxes by utilizing Chapman Petroleum Engineering Ltd. before income tax future net revenue and estimate of income tax. The estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of Petrocapita's tax pools provided by management of Petrocapita and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of Petrocapita's oil and gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of Petrocapita as a business entity, which may be significantly different. The financial statements of Petrocapita for the financial years ended December 31, 2014, 2013 and 2012 are included in this prospectus as Appendix A and should be consulted for additional information regarding taxes.

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of crude oil reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this prospectus are estimates only. The recovery and reserve estimates of the oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable oil reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital

expenditures, marketability of oil, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable oil reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with Petrocapita's assets may vary from the information presented herein and such variations could be material. See "*Notice to Investors – Note on Reserves Data*", "*Forward-Looking Statements*" and "*Risk Factors*".

Readers should review the definitions and information contained in "*Glossary*" and "*Notice to Investors – Unit Abbreviations*" in conjunction with the following tables and notes.

All of Petrocapita's properties are located in Alberta and Saskatchewan.

Summary of Reserves Data (Forecast Prices and Costs)

The tables below summarize data concerning estimates of Petrocapita's proved reserves and probable reserves and related future net revenue as of December 31, 2014, using forecast prices and costs, as evaluated by Chapman Petroleum Engineering Ltd. and contained in the Reserves Report. The summary nature of the tables may result in some numbers differing slightly from those in the Reserves Report due to the effects of rounding, which may also cause some columns not to add exactly.

SUMMARY OF HEAVY OIL RESERVES
as of December 31, 2014
FORECAST PRICES AND COSTS

	HEAVY OIL	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**
PROVED		
Developed Producing	638	583
Developed Non-Producing	105	97
Undeveloped	127	116
TOTAL PROVED	869	795
PROBABLE		
Developed Producing	480	422
Developed Non-Producing	126	112
Undeveloped	813	700
TOTAL PROBABLE	1,418	1,234
TOTAL PROVED PLUS PROBABLE	2,287	2,029

NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2014
BEFORE INCOME TAXES – DISCOUNTED (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% Per Year ($/bbl)
PROVED						
Developed Producing	15,294	12,777	10,931	9,529	8,435	18.76
Developed Non-Producing	2,165	1,738	1,423	1,188	1,007	14.72
Undeveloped	2,774	2,167	1,705	1,346	1,063	14.73
TOTAL PROVED	20,234	16,684	14,060	12,063	10,505	17.68
PROBABLE						
Developed Producing	16,917	11,711	8,598	6,605	5,264	20.37
Developed Non-Producing	3,484	2,555	1,943	1,524	1,227	17.34
Undeveloped	28,929	21,209	15,968	12,289	9,627	27.45
TOTAL PROBABLE	49,332	35,473	26,509	20,417	16,117	21.48
TOTAL PROVED PLUS PROBABLE	69,566	52,158	40,569	32,481	26,623	19.99

NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2014
AFTER INCOME TAXES – DISCOUNTED (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED					
Developed Producing	15,294	12,777	10,931	9,529	8,435
Developed Non-Producing	2,165	1,738	1,423	1,188	1,007
Undeveloped	2,774	2,167	1,705	1,346	1,063
TOTAL PROVED	20,234	16,684	14,060	12,063	10,505
PROBABLE					
Developed Producing	15,417	10,670	7,854	6,058	4,853
Developed Non-Producing	2,559	1,897	1,459	1,158	944
Undeveloped	21,440	15,607	11,653	8,884	6,882
TOTAL PROBABLE	39,416	28,173	20,966	16,099	12,678
TOTAL PROVED PLUS PROBABLE	59,650	44,857	35,026	28,162	23,183

TOTAL FUTURE NET REVENUE
as of December 31, 2014
UNDISCOUNTED
FORECAST PRICES AND COSTS [(1)(2)]

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Development Costs ($000s)	Abandonment and Reclamation Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Taxes ($000s)	Future Net Revenue After Income Taxes ($000s)
Total Proved	60,333	5,394	31,139	2,762	804	20,234	0	20,234
Total Proved plus Probable	169,713	19,223	71,880	7,917	1,128	69,566	(9,916)	59,650

Notes:

(1) Total revenue includes Petrocapita's revenue before royalties.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

FUTURE NET REVENUE BY PRODUCTION GROUP
as of December 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	FUTURE NET REVENUE BEFORE INCOME TAXES [(1)] (DISCOUNTED AT 10%/YEAR) ($000s)	UNIT VALUE BEFORE INCOME TAX [(2)] (DISCOUNTED AT 10%/YEAR) ($/bbl)
PROVED		
Heavy Crude Oil (including solution gas and associated by-products)	14,060	17.68
Total Proved	14,060	17.68
PROVED PLUS PROBABLE		
Heavy Crude Oil (including solution gas and associated by-products)	40,569	19.99
Total Proved Plus Probable	40,569	19.99

Notes:

(1) These figures are derived from volumes that are arithmetic sums of multiple estimates of proved plus probable plus possible reserves, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained above under "*Glossary*".
(2) Unit values of $/boe are based on Petrocapita's net reserves.

Pricing Assumptions

The forecast cost and price assumptions above assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following crude oil benchmark reference pricing, inflation and exchange rates were utilized in the Reserves Report.

SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

Year	Western Canada Select 20.5 API (CDN$/bbl)	Alberta Synthetic Crude Price (CDN$/bbl)	West Texas Intermediate (US$/bbl)	Brent Spot (US$/bbl)	Saskatchewan Light (CDN$/bbl)	Saskatchewan Heavy (CDN$/bbl)	British Columbia Light (CDN$/bbl)	EXCHANGE RATE (US$/CDN$)
2015	59.02	72.86	65.00	69.55	66.31	59.68	71.04	0.88
2016	68.22	84.23	75.00	80.25	76.65	68.98	82.12	0.88
2017	73.75	91.05	81.00	86.67	82.85	74.57	88.77	0.88
2018	77.43	95.59	85.00	90.95	86.99	78.29	93.20	0.88
2019	82.43	101.27	90.00	96.30	92.16	82.94	98.74	0.88
2020	85.71	105.82	94.00	100.58	96.29	86.67	103.17	0.88
2021	87.55	108.09	96.00	102.72	98.36	88.53	105.39	0.88
2022	87.55	108.89	96.00	102.72	98.36	88.53	105.39	0.88
2023	89.32	110.27	97.92	104.77	100.35	90.31	107.52	0.88
2024	91.12	112.50	99.88	106.87	102.37	92.14	109.69	0.88
2025	92.96	114.77	101.88	109.01	104.44	94.00	111.90	0.88
2026	94.84	117.08	103.91	111.19	106.55	95.89	114.16	0.88
2027	96.75	119.45	105.99	113.41	108.70	97.83	116.46	0.88
2028	98.70	121.85	108.11	115.68	110.89	99.80	118.81	0.88
2029	100.69	124.31	110.27	117.99	113.12	101.81	121.20	0.88
2030	102.72	126.82	112.48	120.35	115.40	103.86	123.65	0.88
Constant thereafter								

Notes:

(1) Exchange rates used to generate the benchmark reference prices in this table.
(2) West Texas Intermediate quality (D2/S2) crude (40API) landed in Cushing, Oklahoma.
(3) The Brent Spot price is estimated based on historic data.
(4) Equivalent price for Light Sweet Crude (D2/S2) and Synthetic Crude (34API) landed in Edmonton.
(5) Western Canada Select (20.5API), spot price for British Columbia, Alberta, Saskatchewan, and Manitoba.

Weighted average historical prices realized by Petrocapita for the year ended December 31, 2014, were $72.29/bbl for heavy oil.

Reserves Reconciliation

RECONCILIATION OF GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Heavy Oil		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved plus Probable (Mbbls)
December 31, 2014	869	1,418	2,287
Extensions and Improved Recovery	0	0	0
Technical Revisions	(23)	279	256
Discoveries	0	0	0
Acquisitions	0	279	279
Dispositions	0	0	0
Economic Factors	0	0	0
Production	(110)	0	(110)
December 31, 2013	1,002	860	1,862

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure is required to render them capable of production. Probable undeveloped reserves are the additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The Reserves Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). See "*Risk Factors*".

The following tables sets forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Petrocapita for the years ended December 31, 2014, 2013 and 2012 and, in the aggregate, before that time based on forecast prices and costs.

The capital required to develop the reserves along with the years it is required is set out below. In general though, as also set out below in "Significant Factors or Uncertainties", current price levels will see a focus on infrastructure as opposed to drilling and re-completion until at least 2017.

Proved Undeveloped Reserves

	Heavy Oil (Mbbls)	
Year	**First Attributed**	**Booked Gross**
Prior	0	0
2012	0	0
2013	74	74
2014	53	127

Probable Undeveloped Reserves

	Heavy Oil (Mbbls)	
Year	**First Attributed**	**Booked Gross**
Prior	0	0
2012	34	34
2013	357	391
2014	422	813

Significant Factors or Uncertainties

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. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Other than as discussed above and the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Petrocapita is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of Petrocapita's future net revenue attributable to the reserve categories noted below.

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2015	396	1,726
2016	1,377	5,202
2017	988	988
2018	0	0
2019	0	0
Total (Undiscounted)	2,762	7,917
Total (Discounted at 10%)	2,365	6,949

Petrocapita expects to fund the development costs of its reserves through cash flow from operations, equity and or debt. There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributed in the Reserves Report. Failure to develop those reserves could have a negative impact on Petrocapita's business, financial condition, results of operations, cash flows and future prospects. See "*Risk Factors*".

Interest or other costs of external funding are not included in Petrocapita's reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Petrocapita does not anticipate that interest or other funding costs would make development of any of its properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil Properties

For a description of Petrocapita's principal oil properties please refer to the information provided above under the heading "*Principal Properties*".

Oil Wells

The following table sets forth the number and status of wells in which Petrocapita had a working interest as at December 31, 2014.

	Oil Wells			
	Producing		Non-Producing	
	Gross	Net	Gross	Net
Alberta	45	35.00	30	23.25
Saskatchewan	20	14.75	28	19.00
Total	65	49.75	58	42.25

Properties with no Attributed Reserves

The following table sets out the developed and undeveloped land holdings of Petrocapita as at December 31, 2014.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	2,978	2,312	400	380	3,378	2,692
Saskatchewan	1,584	1,071	1,723	1,703	3,307	2,774
Total	4,562	3,383	2,123	1,783	6,685	5,466

None of the undeveloped land holdings of Petrocapita would expire within one year of the date hereof if not continued.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect Petrocapita's development of its properties to which no reserves are attributed. Petrocapita will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and gas from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Petrocapita. Failure to obtain such financing on a timely basis could cause Petrocapita to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Petrocapita to access sufficient capital for its exploration and development purposes could have a material adverse effect on Petrocapita's ability to execute its business strategy to develop these prospects. See "*Risk Factors*".

The primary economic factors that affect the development of these lands to which no reserves have been attributed are future commodity prices for oil and natural gas (and Petrocapita's outlook relating to such prices) and the future costs of drilling, completing, equipping and operating wells at the time that such activities are considered.

The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

Forward Contracts

Petrocapita's operational results and financial condition will be dependent upon the prices received for oil and gas production. Crude oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors. Supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on the business, financial condition, results of operations, cash flows and future prospects of Petrocapita. See "*Risk Factors*". Petrocapita has no forward hedging or financial contracts at this time.

Additional Information Concerning Abandonment and Reclamation Costs

The costs to abandon and reclaim all of Petrocapita's producing and non-producing wells, gas plants, pipelines, batteries, and other facilities have been estimated by Petrocapita. No estimate of salvage value is netted against these estimated costs for wells. Petrocapita's model for estimating the amount of future abandonment and reclamation expenditures is done at the well and facility levels. Estimated costs for each well and facility are estimated by experienced internal technical personnel. Each well, pipeline and facility is assigned a cost for abandonment and reclamation that is unique to the type of property and taking into account its geographic location, well depth, and producing zones among other factors. The timing of the expenditures is based on the end of the productive life for the specific wells and takes into account governmental requirements. Facility reclamation costs are generally scheduled to begin shortly after the end of the reserve life for the specific field for the associated reserves.

As at December 31, 2014 there were 123 gross (92.0 net) wells for which Petrocapita expects to incur abandonment and reclamation costs.

The following table sets forth abandonment and reclamation costs that Petrocapita expects to incur in respect of its proved plus probable reserves.

Area - Period	**Abandonment and Reclamation Costs Undiscounted ($000s)**	**Abandonment and Reclamation Costs Discounted at 10% ($000s)**
Alberta –2027	5,006	4,832
Saskatchewan – 2029	1,283	1,231
Total - 2029	6,289	6,064

Petrocapita does not expect to incur any material portion of these costs in the next three years.

The future net revenues disclosed in the Reserves Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities, pipelines and non-reserve assigned wells. The Reserves Report deducted approximately $1,128,000 (undiscounted) for abandonment costs of wells with proved and probable reserves in estimating the future net revenues disclosed above.

Tax Horizon

Based on the tax pools of Petrocapita as at December 31, 2014, its anticipated capital spending profile and forecasted commodity prices in the Reserves Report, and assuming development of probable reserves and associated capital expenditures as contemplated in the Reserves Report, Petrocapita expects to pay no income taxes until 2017.

Costs Incurred

The following table summarizes the costs incurred by Petrocapita for the year ended December 31, 2014.

	Year Ended December 31, 2014 ($000s)
Property acquisition costs:	
Proved Properties	–
Unproved Properties	77
Exploration costs	–
Development Costs	1,747
Total	1,824

Exploration and Development Activities

The following table sets forth the gross and net development wells in which Petrocapita participated during the year ended December 31, 2014.

	Development Wells	
	Gross	**Net**
Natural Gas	–	–
Oil	2	1.7
Service	–	–
Stratigraphic Test	–	–
Dry	–	–
Total	2	1.7

For a description of Petrocapita's exploration and development activities, see "*Description of the Business – Business Strategy and Objective*".

Production Estimates

The following table sets out the gross volume of production estimated for the year ended December 31, 2015 reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables set forth above, together with information regarding the portion of those estimated first-year production volumes attributed to the Lloydminster field.

Reserves Category	**Heavy Oil (Mbbls)**	**Heavy Oil (bbls/d)**
TOTAL PROVED	**126**	**345.2**
Lloydminster (Alberta)	77	210.8
Other	49	134.4
TOTAL PROBABLE	**32**	**87.7**
Lloydminster (Alberta)	7	19.2
Other	25	68.5
TOTAL PROVED PLUS PROBABLE	**158**	**432.9**

All of Petrocapita's Alberta production is attributable to its Lloydminster field, which is the only property that accounts for 20% or more of Petrocapita's estimated 2015 production as evaluated in the Reserves Report.

Production History

The following tables summarize certain information in respect of the production, product prices received, royalties paid, production expenses and resulting netback for the periods indicated below.

	Quarter Ended 2014				
	March 31	**June 30**	**September 30**	**December 31**	**Period Ended Dec. 31, 2014**
Average Daily Production					
Heavy oil (bbls/d)	421	384	380	334	379
Average Realized Price					
Heavy oil ($/bbl)	71.91	82.38	76.99	55.87	72.29
Royalties Paid					
Heavy oil ($/bbl)	10.53	16.06	13.46	9.61	12.74
Production Expenses					
Heavy oil ($/bbl)	44.12	38.64	36.79	34.45	38.75
Transportation Expenses					
Heavy oil ($/bbl)	3.06	4.42	3.59	2.21	3.21
Netback Received					
Heavy oil ($/bbl)	14.2	23.26	23.15	9.61	17.72

The following table indicates the average daily production for the period ended December 31, 2014.

	Heavy Oil (bbls/d)
Alberta (Lloydminster Field)	232.6
Saskatchewan	130.5
Skim Oil from processing	16.2
Total	379.3

The Lloydminster field in Alberta is the only property that accounted for 20% or more of Petrocapita's average daily production for 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis of the Trust for the financial years ended December 31, 2014 and 2013, respectively, and for the three and six month periods ended June 30, 2015, is attached as Appendix B, and should be read in conjunction with the annual and interim financial statements for such periods (including in each case the notes thereto) attached as Appendix A.

SELECTED FINANCIAL AND OPERATING INFORMATION

Financial years ended December 31, 2014, 2013 and 2012

The following table presents selected historical consolidated financial and operating information of the Trust at the dates and for the annual periods indicated. The figures given below should be read in conjunction with the audited consolidated financial statements of the Trust for the financial years ended December 31, 2014, 2013 and 2012, respectively, attached as Appendix A, and the related management's discussion and analysis for the financial years ended December 31, 2014 and 2013, respectively, attached as Appendix B.

	Year Ended December 31		
	2014	**2013**	**2012**
Financial ($000s)			
Oil sales [1]	10,344	8,772	4,406
Funds flow from operations [2]	2,254	1,738	631
Net income (loss)	(3,937)	(3,714)	(4.375)
Total long term assets	27,845	27,548	15,571
Total assets	31,365	32,988	31,274
Total financial liabilities	37,623	35,422	30,091
Net debt (surplus) [2]	(573)	(3,748)	(14,805)
Operating			
Oil Production (bbls/d)	374	365	187
Average realized price			
Oil revenue ($/bbl)	73.33	65.79	64.37
Water disposal revenue ($/bbl)	2.45	0.08	–
Operating netback			
Royalties ($/bbl)	(12.64)	(9.58)	(9.52)
Production expense ($/bbl)	(37.94)	(34.55)	(34.76)
Transportation expense ($/bbl)	(3.40)	(3.38)	(2.78)
Operating netback ($/bbl) [2]	21.80	18.36	17.31
General and administrative expense ($/bbl)	(5.20)	(5.31)	(8.10)
Funds flow netback ($/bbl)	16.60	13.05	9.21

Notes:

(1) Includes oil revenue, skim oil revenue and oil royalty revenue.
(2) See "*Notice to Investors – Non-IFRS Measures*".

Six month periods ended June 30, 2015 and 2014

The following table presents selected historical consolidated financial and operating information of the Trust at the dates and for the interim periods indicated. The figures given below should be read in conjunction with the consolidated financial statements of the Trust for the three and six month periods ended June 30, 2015 and 2014, attached as Appendix A, and the related management's discussion and analysis for the three and six month periods ended June 30, 2015, attached as Appendix B.

	Six Months Ended June 30	
	2015	**2014**
Financial ($000s)		
Oil sales [1]	1,883	5,625
Funds flow from operations [2]	(52)	1,404
Net income (loss)	(1,234)	(1,394)
Total long term assets	31,705	27,940
Total assets	33,647	33,295
Total financial liabilities	10,672	37,070
Net debt (surplus) [2]	(169)	(3,238)
Operating		
Oil Production (bbls/d)	255	404
Average realized price		
Oil revenue ($/bbl)	40.77	76.87
Water disposal revenue ($/bbl)	0.82	1.84
Operating netback		
Royalties ($/bbl)	(3.94)	(13.23)
Production expense ($/bbl)	(27.22)	(37.91)
Transportation expense ($/bbl)	(2.14)	(3.72)
Operating netback ($/bbl) [2]	8.29	23.85
General and administrative expense ($/bbl)	(9.42)	(4.69)
Funds flow netback ($/bbl)	(1.13)	19.16

Notes:

(1) Includes oil revenue, skim oil revenue and oil royalty revenue.
(2) See "*Notice to Investors – Non-IFRS Measures*".

DECLARATION OF TRUST

The Trust is an unincorporated investment trust created January 22, 2010 pursuant to the Declaration of Trust and currently qualifies as a "mutual fund trust" pursuant to the Tax Act. The Trust is formed under and governed by the laws of the Province of Alberta. Following is a summary only of certain material provisions of the Declaration of Trust, which is qualified in its entirety by the complete text of the Declaration of Trust, a copy of which will be available at www.sedar.com under the Trust's profile.

Undertaking of the Trust

The Declaration of Trust provides that the activities of the Trust are, in general, restricted to the following: (a) acquiring, holding, transferring, disposing of, investing in, lending to, and otherwise dealing with, assets, securities (whether debt or equity) and other interests or properties of whatever nature or kind of, or issued by, any person (including the Partnership) and making such other investments as the Trustees in their sole discretion determine; (b) holding cash and other investments in connection with and for the purposes of the Trust's activities, including paying liabilities of the Trust (including administration expenses), paying any amounts required in connection with the redemption of Units, and making distributions to Unitholders; (c) disposing of all or any part of the Trust's property; (d) issuing Units and other securities of the Trust (including debt instruments, securities convertible into or exchangeable for Units or other securities of the Trust, or warrants, options or other rights to acquire Units or other securities of the Trust), for the purposes of, without limitation, (i) conducting, or facilitating the conduct of, the activities and undertaking of the Trust (including for the purpose of raising funds for acquisitions), (ii) repayment of any indebtedness or borrowings of the Trust or any affiliate thereof, (iii) establishing and implementing Unitholder rights plans, distribution reinvestment plans, Unit purchase plans, and incentive option and other compensation plans of the Trust, if any, (iv) satisfying obligations to deliver securities of the Trust pursuant to the terms of securities convertible into or exchangeable therefor (whether or not such convertible or exchangeable securities have been

issued by the Trust); (v) carrying out any of the transactions contemplated by any offering documents of the Trust and satisfying all obligations in connection with such transactions, and (vi) making non-cash distributions to Unitholders, including *in specie* redemptions as well as distributions; (e) repurchasing or redeeming Units or securities of the Trust, subject to the provisions of the Declaration of Trust and applicable law; (f) issuing debt securities or otherwise borrowing funds, as well as mortgaging, pledging, charging, granting a security interest in or otherwise encumbering all or any part of the Trust's property, whether as security for obligations of the Trust or otherwise; (g) guaranteeing any obligations, indebtedness or liabilities, present or future, direct or indirect, absolute or contingent, matured or not, of any person for, or in pursuit of pursuing or facilitating the business and purposes of the Trust, and mortgaging, pledging, charging, granting a security interest in or otherwise encumbering all or any part of the Trust's property as security for such guarantee; (h) carrying out any of the transactions, and exercising, performing and satisfying any of the rights, liabilities and obligations of the Trust under any agreements or arrangements, entered into in connection with pursuing the business and purposes of the Trust; and (i) engaging in all activities, and taking all such actions, ancillary or incidental to any of those activities set forth in clauses (a) through (h) above.

Trustees

The Trust will have a minimum of two (2) and a maximum of eleven (11) trustees. The number of trustees within such range shall be determined by resolution of the Trustees, and that number may be changed from to time. As at the date hereof, the Trustees have determined that there shall be four (4) trustees.

Subject only to the specific limitations and restrictions contained in the Declaration of Trust, the Trustees are vested with and have, without any further authorization, action or consent required, full, continuing, absolute and exclusive power, control and authority over the Trust's property and over the business and undertaking of the Trust to the same extent as if the Trustees were the sole and absolute beneficial owners of such property and may do all such acts and things as in their sole judgment and discretion are necessary or incidental to, or desirable for, the carrying out of the terms of the trust created by the Declaration of Trust.

All determinations of the Trustees and any agent to whom the Trustees have delegated duties (including the Administrator), where made in good faith with respect to any matters relating to the Trust, shall be final and conclusive and shall be binding upon the Trust and all Unitholders. Trustees may appoint from their number one or more committees of Trustees for any purpose they deem advisable from time to time, and may delegate to any such committee any, but not all, of the powers of the Trustees. Questions arising at any meeting of Trustees shall be decided by a majority.

The Trustees will be appointed at each annual meeting of Unitholders by Ordinary Resolution, to hold office for a term expiring at the close of the next annual meeting of Unitholders or until successors are duly elected or appointed, or their earlier death, resignation or removal in accordance with the Declaration of Trust. Trustees may be removed at any time by Ordinary Resolution. If a Trustee resigns, a majority of the Trustees remaining in office may appoint an individual as a replacement Trustee (and if they fail to do so then the Administrator may appoint such replacement).

The Trustees may, between annual meetings of Unitholders, appoint one or more additional Trustees to serve until the close of the next annual meeting of Unitholders, but the number of additional Trustees shall not at any time exceed one-third of the number of Trustees who held office at the expiration of the immediately preceding annual meeting of Unitholders.

A Trustee shall be an individual or a corporation duly authorized and registered to carry on the business of a trust company in Canada. An individual is disqualified from being a Trustee if he or she is less than 18 years of age, does not have the full exercise of his or her civil rights, is of unsound mind and has been so found by a court in Canada or elsewhere, or has the status of bankrupt. All Trustees must be residents of Canada within the meaning of the Tax Act.

Trustees are entitled to receive, for their services as Trustees, such reasonable compensation as the Trustees may determine from time to time, as well as reimbursement for out-of-pocket expenses incurred in acting as a Trustee. A Trustee shall not be required to devote his or her entire time to the affairs of the Trust.

The standard of care required of each Trustee under the Declaration of Trust is that, in exercising their powers and carrying out their functions thereunder, they do so honestly and in good faith with a view to the best interests of the Trust and that, in connection therewith, they exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Trustees shall be deemed to have satisfied this standard of care to the extent that the performance of certain duties and activities has been granted or delegated to the Administrator. In general, each Trustee shall be indemnified and reimbursed out of the Trust's property against all liabilities or claims against them or the Trust, and they shall have no liability to any holders of Units, where such liabilities or claims arise out of being or having been a trustee of the Trust, unless such liabilities or claims arise as a result of the Trustee failing to satisfy the expressed standard of care or, in the case of criminal or administrative action or proceeding that is enforced by monetary penalty, where such Trustee did not have reasonable grounds for believing that his conduct was lawful.

Administrator

The Trustees have delegated to the Administrator, under the terms of the Administration Agreement, the obligation to provide and perform for and on behalf of the Trust essentially all services that are or may be required or advisable, from time to time, in order to manage, administer and govern the operations of the Trust. The Administration Agreement sets forth all of the rights, restrictions and limitations (including, without limitation, limitations of liability and indemnification rights) which pertain to the performance by the Administrator of the duties delegated to it by the Trustees. Pursuant to the terms of the Declaration of Trust, those rights, restrictions and limitations also apply in all respects to the Administrator in the exercise and performance by it of all powers, duties and authorities conferred upon or delegated to the Administrator under the terms of the Declaration of Trust. See "*Administration Agreement*".

Conflict of Interest

In addition to his or her interest as a Trustee of the Trust, a Trustee may have other interests or associations of whatever nature or kind. By the terms of the Declaration of Trust, the Unitholders agree that any Trustee may be a securityholder, director, officer, trustee, employee, agent or consultant of (or otherwise involved with) the Administrator, or any associate or affiliate of either. Without limiting the foregoing, the Declaration of Trust expressly provides that each Trustee is permitted: (a) to be an associate, affiliate, securityholder, director, officer, trustee, employee, agent or consultant of, or otherwise involved with, a person from or to whom assets of the Trust have been or are to be purchased or sold; (b) to be a person, or to be an associate, affiliate, securityholder, director, officer, trustee, employee, agent or consultant of (or otherwise involved with) a person, with whom the Trust contracts or deals or which supplies services to the Trust; (c) to acquire, hold and dispose of, for such Trustee's own account, any property (real, personal, tangible or intangible) even if such property is of a character which could be held by the Trust, and to exercise all rights of an owner of such property as if such Trustee were not a Trustee; (d) to acquire, hold and sell Units as principal, or as an affiliate or associate of or fiduciary for any other person, and to exercise all rights of a holder thereof as if such Trustee was not a Trustee; and (e) to have business interests of any nature and to continue such business interests while a Trustee.

Under the terms of the Declaration of Trust, the Unitholders acknowledge and accept that there are, and will continue to be, potential or actual interests of one or more of the Trustees, or their associates or affiliates (including conflicts of interest) with respect to business or other interests held directly or indirectly by, and/or contractual arrangements or transactions directly or indirectly involving, one or more of the Trustees, or their respective associates or affiliates, and the Unitholders agree that:

(a) any Trustee is permitted (notwithstanding any liability which might otherwise be imposed by law or in equity upon such Trustee as a trustee of the Trust) to derive direct or indirect benefit, profit or advantage from time to time as a result of dealing with the Trust or its affiliates or as a result of the relationships, matters, contracts, transactions, affiliations or other interests it may have and such Trustee shall not be liable in law or in equity to pay or account to the Trust, or to any Unitholder (whether acting individually or on behalf of itself and other Unitholders as a class) for any such direct or indirect benefit, profit or advantage nor, in such circumstances, will any contract or transaction be void or voidable at the instance of the Trust of any Unitholder or any other person; and

(b) interests of any Trustee, or their respective associates or affiliates, including any conflicts of interest, will not form the basis for any claim against such Trustee, or their respective affiliate or associate, or for any attempt to challenge or attack the validity of any contract, transaction or arrangement (or renewal, extension or amendments of same) which the Trustees may enter into on behalf of the Trust;

provided, in each case, that the Trustee in question has otherwise exercised its powers and discharged its duties, as set out in the Declaration of Trust, honestly and in good faith in respect to the matter, contract, transaction or interest in question.

Units

Beneficial interests in the Trust are represented and constituted by two classes of Units – being Trust Units and Preferred Units – of which an unlimited number of each class are authorized and may be issued. The rights, privileges, restrictions and conditions attached to the Trust Units and the Preferred Units are set out in the Declaration of Trust and are summarized below and under "*Securities of the Trust*". Trust Units and Preferred Units, as well as any other securities of the Trust, may be created, issued, sold and delivered at the times, to the persons, for the consideration, and otherwise on the terms and conditions determined by the Trustees in their absolute discretion.

The Trustees may, in their discretion, at any time and from time to time, subdivide or consolidate each or either class of Units outstanding.

Subject to any discounts that the Trustees may allow as consideration for agreeing to subscribe for Units, Units are only to be issued when fully paid, and they are not subject to future calls or assessment; provided, however, that Units issued under an offering may be issued for a consideration payable in instalments and the Trust may take security over any such Units for unpaid instalments. The consideration for any Unit issued by the Trust shall be paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit has been issued for money; provided that property may include a promissory note.

There are no pre-emptive rights attaching to either the Trust Units or the Preferred Units as a class.

Distribution Rights; Distributable Cash

Holders of Trust Units are entitled to receive non-cumulative distributions only if, as and when declared by the Trustees in accordance with the provisions of the Declaration of Trust. **Any such distributions are discretionary and there is no assurance that they will be declared on a regular or consistent basis or at all.** The discretionary distribution rights attached to the Trust Units are also subject to preferential distribution rights attached to the Preferred Units (to the extent any Preferred Units are outstanding at the relevant time). See "*Distribution Policy*" and "*Risk Factors*".

The preferential distribution rights of the Preferred Units provide that (i) to the extent distributable cash is available, the Trustees shall, in respect of each distribution period, declare and pay to holders of Preferred Units, in priority to any other distributions, a fixed, preferential cumulative distribution at the rate of $0.1025 per Preferred Unit per annum (adjusted for any portion of the distribution period during which the unit was not outstanding), and (ii) in the event of a distribution of distributable cash that is in excess of unpaid amounts in respect of declared distributions on the Preferred Units (to the extent not already taken into account in calculating distributable cash), holders of Preferred Units as of the applicable distribution record date shall be entitled to an equal proportionate 10% share thereof up to a maximum additional amount (above the fixed annual amount of $0.1025) of $0.0175 per Preferred Unit per annum. The remainder of any such distribution of excess distributable cash would be payable to the holders of Trust Units as of the applicable distribution record date.

The distribution provisions of the Declaration of Trust are contained in Article 5 thereof. Any distributions declared or deemed payable under Article 5 are to be paid in cash, unless the Trustees determine that the Trust does not have cash in an amount sufficient to make full payment of the amount of any distribution declared or deemed payable on the due date therefor, or where cash payment is otherwise determined undesirable in the discretion of the Trustees,

in which case the payment may, at the option of the Trustees, include the issuance of additional Units of the same class as the Units on which the distribution is being paid.

For purposes of the Declaration of Trust, the "distributable cash" of the Trust for or in respect of any distribution period shall be all cash amounts received by the Trust for, or in respect of, such distribution period, including amounts on account of interest, income, dividends, returns of capital, amounts paid on debt held by the Trust, capital gains, and such other amounts as may be determined from time to time by the Trustees or the Administrator to be included in "distributable cash" (which may include amounts taken, in the discretion of the Trustees or the Administrator, out of the Trust's reserves as well as amounts from the proceeds of any offering of Units or other securities (including debt securities), reduced by the sum of (i) all amounts paid on account of expenses and liabilities for, or in respect of, such distribution period as well as an amount for all expenses and liabilities of the Trust which, in the opinion of the Trustees or Administrator, may reasonably be considered to have accrued and become owing in respect of, or which relate to, such distribution period or a prior distribution period if not accrued in such prior period (including, without limitation, any accrued liability in respect of any undeclared and accumulated distributions on the Preferred Units), (ii) all amounts which relate to the repayment of any amount (principal or interest) in respect of any indebtedness of the Trust during such distribution period, (iii) all cash amounts used during such distribution period for investments or other acquisitions of assets by the Trust, (iv) the aggregate amount of all cash amounts used, or to be used, in respect of the redemption or repurchase of Units called for redemption or repurchase, (iv) any further amount that the Administrator may reasonably consider to be necessary to provide for the payment of any liabilities which have been or will be incurred by the Trust, including any tax liability of the Trust (to the extent that such liabilities have not otherwise been taken into account in determining distributable cash), or for pursuing any purpose or activity of the Trust, and (vi) an amount as determined in the discretion of the Trustees or the Administrator for reasonable reserves to be maintained for the purposes of satisfying payment of any amounts or liabilities of the Trust.

The Trustees or the Administrator may from time to time determine the distribution period, which as at the date hereof means each three month period ending March 31, June 30, September 30 and December 31 in each calendar year.

The Trustees shall deduct or withhold from any distribution payment to a Unitholder all amounts required by law to be withheld from such payment, whether in the form of cash, additional Units or otherwise.

Redemption Rights

Units are redeemable at any time on demand by the holders thereof, on sending a duly completed and properly executed notice, in form approved by the Trustees, to the head office of the Trust or to the transfer agent for the class of Units being redeemed together with the certificate or certificates representing the Units to be redeemed, at a redemption price per Unit equal to 90% of the fair market value thereof, as at the date upon which the Units were tendered for redemption, as determined by the Administrator in its sole discretion, acting reasonably, but having regard to: (i) all prices at which trades of Units of the same class have been transacted, and the issue prices for Units of the same class issued in any offering, during the preceding 6-month period (or such other period as the Administrator determines relevant and reasonable); (ii) the fair market value of equity interests in, or enterprise values of, comparable entities substantially similar to the Trust; and (iii) any other considerations which the Administrator, in its discretion, determines relevant for purposes of determining the redemption price; provided, however, that if at the time Units are tendered for redemption the outstanding Units of the same class are listed, traded or quoted on a stock exchange or market which the Trustees consider, in their sole discretion, provides representative fair market value prices for such Units (the "**Principal Market**") then the redemption price shall instead be the lesser of:

(i) 90% of the "market price" of Units of such class, as determined on the Principal Market, during the ten (10) trading days preceding the date on which the Units were tendered for redemption; and

(ii) 100% of the "closing market price" of Units of such class, as determined on the Principal Market, on the date that the Units were tendered for redemption;

unless the normal trading of the outstanding Units of the same class as the Units being redeemed is suspended or halted on any stock exchange on which such Units are listed for trading or, if not so listed, suspended or halted on any market on which such Units are quoted for trading, for more than 10 trading days during the 20-day trading period immediately preceding the date on which the Units being redeemed were tendered for redemption (in which case the redemption price shall be as determined by the Administrator in its sole discretion, acting reasonably, having regard to the factors cited above).

For this purpose:

- the "market price" of a Unit shall be: (i) an amount equal to the volume weighted average trading price of such a Unit for each of the 10 trading days; (ii) if the Principal Market does not provide information necessary to compute a volume weighted average trading price, an amount equal to the volume weighted average of the closing prices of such a Unit for each of the 10 trading days on which there was a closing price; provided, however, that if the Principal Market does not provide a closing price but only provides the highest and lowest prices of such Units traded on a particular day, the "market price" shall be an amount equal to the volume weighted average of the highest and lowest prices for each of the trading days on which there was a trade; and (iii) if there was trading on the Principal Market for fewer than 5 of the 10 trading days, the "market price" shall be the volume weighted average of the following prices established for each of the ten (10) trading days: (A) the average of the last bid and last asking prices for each day on which there was no trading; (B) the closing price of such Units for each day that there was trading if the Principal Market provides a closing price; and (C) the average of the highest and lowest prices of such Units for each day that there was trading, if the Principal Market provides only the highest and lowest prices of such Units traded on a particular day; and

- the "closing market price" of a Unit shall be: (i) an amount equal to the volume weighted average trading price of such Unit on the date on which the Units were tendered for redemption, if the Principal Market provides information necessary to compute a volume weighted average trading price on such date; (ii) an amount equal to the closing price of such a Unit if there was a trade on the date on which the Units were tendered for redemption, and the Principal Market provides only a closing price; (iii) an amount equal to the simple average of the highest and lowest prices of such Units if there was trading on the date on which the Units were tendered for redemption and the Principal Market provides only the highest and lowest trading prices of such Units traded on a particular day; or (iv) the simple average of the last bid and last ask prices of such Units if there was no trading on the date on which the Units were tendered for redemption.

If there is more than one exchange or market on which Units of the class being redeemed are listed or quoted for trading, the Principal Market shall be the exchange or market on which the Units are listed or quoted for trading that is designated by the Trustees in their absolute discretion; and if the Principal Market is not open for trading on the date on which the Units are tendered for redemption, then the reference date shall be the last day on which such Principal Market was open for trading.

The redemption price payable in respect of Units so redeemed during any calendar month shall be paid by cheque no later than the end of the month immediately following the end of the calendar month in which the Units were tendered for redemption; provided, however, that if the total redemption amount payable by the Trust in respect of all Units tendered for redemption in the same calendar month exceeds $7,500, then the Trustees shall not be obligated to make cash payment greater than $7,500 (but may elect to do so in their sole discretion), and any balance of the aggregate redemption price for Units redeemed that month that is not paid in cash shall, subject to receipt of any applicable regulatory approvals, be paid by the Trust, in the Administrator's discretion, through the issuance of unsecured five-year promissory notes and/or an *in specie* distribution of property of the Trust having an aggregate fair market value equal to that portion of the aggregate redemption price not paid in cash. The cash portion of any such aggregate redemption price shall be paid pro rata to redeeming Unitholders based upon the proportion which the redemption amount payable to a redeeming Unitholder bears in relation to the aggregate redemption price payable in respect of all Units tendered for redemption in such calendar month. Any promissory notes issued on a redemption of Units will (ii) have a principal amount equal to that portion of the redemption price being paid through the issuance of such notes, (ii) bear interest at a market rate determined at the time of issuance (based on the advice of an independent financial advisor) but payable only at maturity, (iii) be unsecured and subordinated and postponed to all senior indebtedness (being all indebtedness, liabilities and obligations of the Trust not expressed to

rank in right of payment subordinate to or *pari passu* with the indebtedness evidenced by the redemption notes) as well as any payments and other obligations owed in respect of the Preferred Units, if any, (iv) be due and payable on the fifth anniversary of the date of issuance, subject to earlier prepayment; and (v) be subject to such other standard terms and conditions as would be included in a note indenture for long-term promissory notes of this kind, as may be approved by the Trustees.

Additionally, the Trust may at its election, at any time and from time to time, redeem all or any part of the outstanding Preferred Units (if any), as determined by the Trustees, on not less than 21 days' notice to the affected holders, at a redemption price per Preferred Unit equal to the sum of (a) the quotient obtained when the aggregate gross proceeds from the issuance of all Preferred Units issued since formation of the Trust and still outstanding is divided by the aggregate number of Preferred Units then issued and outstanding; and (b) all accrued and unpaid cumulative distributions in respect of such Preferred Unit, whether or not declared, calculated to but excluding the date of redemption. The redemption price payable in respect of Units so redeemed at the election of the Trust shall be paid by cheque on presentation and surrender at the registered office of the Trust or any other place designated in the redemption notice of the certificates representing the Preferred Units called for redemption.

The Trustees shall deduct or withhold from any redemption payment to a Unitholder all amounts required by law to be withheld from such payment, whether in the form of cash, promissory notes or otherwise.

Conversion of Preferred Units to Trust Units

The Preferred Units are convertible into fully paid and non-assessable Trust Units at the sole option of the Trust, in whole or in part (on a pro rata basis if less than all of the Preferred Units are to be converted), at any time and from time to time, on not less than 30 days' written notice prior to the effective date of conversion, all in accordance with the provisions of the Declaration of Trust.

Any outstanding Preferred Units will also automatically convert into Trust Units, without any further action required by the Trust, a Unitholder or any other person, in the event of (i) a plan of arrangement, amalgamation, reorganization or other business combination (other than an internal reorganization) involving the Trust and/or the Unitholders where holders of Units receive, in exchange for all Units held by them, cash, securities or a combination thereof and, where the consideration consists of securities, such securities are listed on a stock exchange or quotation system and are not subject to resale restrictions (other than those applicable to "control persons" under applicable securities laws), or (ii) the listing and posting for trading of the Trust Units on a stock exchange; unless, in either case, the holders of the Preferred Units have voted in favour of effecting a different result than the conversion of Preferred Units upon occurrence of any such event.

The conversion ratio at which Preferred Units are convertible into Trust Units will be determined according to the formula set forth in the Declaration of Trust. That formula is primarily a function of (i) the aggregate gross proceeds from the original issue by the Trust of all Preferred Units being converted, and (ii) the deemed equity value of the Trust Units based on the consolidated net income of the Trust for and in respect of the two financial quarters preceding the date of conversion (provided that the most recent such quarter ended at least 45 days before the conversion date), as adjusted in accordance with the provisions of the Declaration of Trust.

More particularly, in the event of a conversion of Preferred Units to Trust Units, a former holder of Preferred Units shall receive, in respect of its converted Preferred Units, such number of Common Units as is equal to the product obtained when (i) the aggregate gross proceeds from the original issue by the Trust of all Preferred Units being converted, as divided by Common Unit Price (defined below), is multiplied by (ii) a fraction, the numerator of which is the number of Preferred Units of such holder being converted and the denominator of which is the aggregate number of all Preferred Units being converted. For purposes of this calculation:

- "Common Unit Price" means the price per Trust Unit as is determined when (i) Equity Value is divided by (ii) the number of Trust Units issued and outstanding as of the conversion date (without giving effect to the conversion of Preferred Units on such date);

- "Equity Value" means the result obtained when Conversion EBITDA is annualized and then multiplied by two (2);

- "Conversion EBITDA" means the EBITDA of the Trust, as determined by its auditors at the time, for and in respect of the two financial quarters immediately preceding the conversion date provided that the most recent of those financial quarters has ended at least 45 days prior to the conversion date;

- "EBITDA" means, for any period with respect to the Trust, the Net Income of the Trust for such period, determined on a consolidated basis, as the same is increased (without duplication) by the sum of "total interest expense", "income tax expense", "depreciation expense" and "minority interest reduction" for such period (as the terms "total interest expense", "income tax expense", "depreciation expense" and "minority interest reduction", respectively, are defined in the Declaration of Trust); in each case to the extent that such amounts were included as deductions in arriving at the calculation of Net Income for the period; and

- "Net Income" means, for any period with respect to any person, the net revenue of such person, determined on a consolidated basis, for such period, less all expenses and other charges not otherwise deducted in computing such net revenue for such period, determined in accordance with Canadian generally accepted accounting principles, but excluding extraordinary items as determined in accordance therewith.

Holders of Preferred Units that have been converted will be entitled, upon presentation and surrender at the registered office of the Trust in Calgary, Alberta or such other place(s) in Canada as may be specified in the notice of conversion, of the certificates representing the Preferred Units so converted, to receive certificates representing the Trust Units into which their Preferred Units were converted.

From and after the conversion date of any Preferred Units, the holders thereof shall be deemed to be holders of Trust Units and shall not be entitled to any rights as holders of Preferred Units in respect thereof unless certificates for Trust Units are not issued upon presentation and surrender of certificates for the converted Preferred Units as required under the Declaration of Trust.

The Trust shall have the right, at any time after mailing a notice of conversion of any Preferred Units, to send by prepaid registered mail certificates representing the Trust Units issued upon conversion to the address of the holders of the Preferred Units called for conversion, as set forth in the register of the Trust.

Unless otherwise determined by the Trustees, fractional Trust Units will not be issued in connection with a conversion of Preferred Units.

Meetings of Unitholders

The Declaration of Trust provides that meetings of Unitholders entitled to vote will be called and held annually for the election of Trustees and, if so determined by the Unitholders in accordance with the Declaration of Trust, the appointment of auditors of the Trust, the presentation of consolidated financial statements of the Trust for the preceding fiscal year, and the transaction of such other business as the Trustees or Administrator may determine or as may otherwise be properly brought before the meeting. The Unitholders will be entitled to pass resolutions that have binding effect upon the Trustees or the Trust only with respect to:

- the appointment or removal of one or more Trustees;

- the appointment or removal of the auditors of the Trust;

- any necessary consent to amendments to the Declaration of Trust proposed by the Trustees;

- wind-up and termination of the Trust;

- the sale of all or substantially all of the assets of the Trust; and

- any other matters required under applicable securities laws, stock exchange requirements or other laws or regulatory requirements to be submitted to Unitholders for consent or approval.

Except as specifically provided in the Declaration of Trust, no resolution or other action of Unitholders will in any way bind the Trustees.

Unless otherwise expressly provided in the Declaration of Trust, any action taken or resolution passed in respect of any matter at a meeting of Unitholders shall be by Ordinary Resolution. Such matters include the appointment or removal of Trustees, and the appointment or removal of auditors of the Trust.

Matters requiring Unitholder approval by Special Resolution include:

- any sale, lease, exchange, transfer or other disposition of all or substantially all of the property of the Trust, other than (i) pursuant to the wind-up and termination of the Trust and in specie redemptions or distributions permitted under the Declaration of Trust, (ii) in order to acquire securities of the Partnership or other affiliate of the Trust, or (iii) in conjunction with an "internal reorganization" of the Trust (and for this purpose an "internal reorganization" means the sale, lease, exchange, transfer or other disposition of the assets of a person, whether or not involving all or substantially all of the assets of such person, as a result of which such person has substantially the same interest, whether direct or indirect, in such assets that it had prior to the reorganization and, for greater certainty, may include an amalgamation, arrangement or merger of such person and its affiliates with any other entities); or

- an amendment to the Declaration of Trust, except as described below under "*Declaration of Trust – Amendments*"; and

- a wind-up and termination of the Trust upon the proposal, to the holders of Trust Units, of the Administrator.

Every Ordinary Resolution and every Special Resolution passed in accordance with the provisions of the Declaration of Trust at a meeting of Unitholders shall be binding upon all the Unitholders, whether present at or absent from such meeting, and each and every Unitholder shall be bound to give effect to every such Ordinary Resolution and Special Resolution.

Holders of Preferred Units are not entitled to receive notice of, attend or vote at any meeting of Unitholders or to otherwise vote in respect of any matter requiring Unitholder approval unless the matter for which approval is being sought is:

(a) to amend the rights, privileges, restrictions and conditions attaching to the Preferred Units, including amendments to: remove or change rights to distributions in a manner materially prejudicial to holders of Preferred Units; add, remove or change, redemption rights in a manner materially prejudicial to holders of Preferred Units; reduce or remove a distribution preference or a liquidation preference; or add, remove or change, in a manner materially prejudicial to holders of Preferred Units, conversion privileges, voting, transfer or pre-emptive rights, or rights to acquire other securities; or

(b) to carry out and give effect to any of the following actions if the resulting affect to the holders of Preferred Units would be materially prejudicial thereto: effect an exchange, reclassification or cancellation of all or part of the Preferred Units; increase the rights or privileges of any Units of the Trust having rights or privileges equal or superior to the Preferred Units; create a new class of units of the Trust equal or superior to the Preferred Units; make any class of Units of the Trust having rights or privileges inferior to the Preferred Units equal or superior to the Preferred Units; or effect an exchange or create a right of exchange of all or part of the units of another class of Units of the Trust into the Preferred Units;

in which case (i) the Trust shall call and hold a meeting of Unitholders at which only holders of Preferred Units may attend and vote, and (ii) matters put forth at such meeting, to be approved, must be approved by Special Resolution of the holders of Preferred Units, voting separately as a class; and (iii) at the meetings, each holder of Preferred Units shall be entitled to one vote in respect of each Preferred Unit held; provided, however, that all matters set forth above must also be approved by the holders of the Trust Units, voting separately as a class, in accordance with the terms of the Declaration of Trust.

A meeting of Unitholders may be called at any time and for any purpose by the Trustees or upon request of the Administrator, or if validly requisitioned in writing by holders of not less than 25% of the Units then outstanding (except in certain circumstances). A requisition must disclose the name, address and holdings of each person supporting the requisition and state in reasonable detail the business proposed to be transacted at the meeting.

Unitholders entitled to attend and vote at a meeting may do so in person or by proxy, and a proxyholder need not be a Unitholder. A quorum for any meeting of Unitholders shall be one or more persons present in person and being, or representing by proxy, Unitholders holding in aggregate not less than 5% of all votes entitled to be cast at the meeting.

The Declaration of Trust contains provisions as to the required notice and other procedures pertaining to the calling and holding of meetings of Unitholders.

Limitation on Non-Resident Ownership

At no time may Non-residents be the beneficial owners of more than 49% of the outstanding Units, on both a non-diluted and fully-diluted basis (which includes, for greater certainty, Units which are issuable pursuant to any outstanding exchangeable securities of the Trust), and it shall be the responsibility of the Administrator to monitor compliance by the Trust with this Non-resident restriction in accordance with the published policies of the relevant taxation authority. The Declaration of Trust grants the Administrator the power and authority to take all such action as it determines in its discretion is reasonable and practicable in the circumstances in order to ensure compliance by the Trust with the Non-resident restriction, including the ability of the Administrator to sell Units beneficially owned by Non-residents.

Amendments

Except where specifically provided otherwise in the Declaration of Trust, when the Trustees may make amendments without the consent, approval or ratification of Unitholders, the Declaration of Trust may only be amended by Special Resolution.

The Trustees may, at any time and from time to time, without the consent, approval or ratification of the Unitholders or any other person, amend the Declaration of Trust for the purpose of:

(a) ensuring continuing compliance by the Trust, with applicable laws, regulations, requirements or policies of any court or governmental or regulatory authority having jurisdiction over the Trustees or the Trust;

(b) providing, in the opinion of the Trustees, additional protection for the Unitholders or to obtain, preserve or clarify the provision of desirable tax treatment to Unitholders;

(c) making amendments hereto which, in the opinion of the Trustees, are necessary or desirable in the interests of the Unitholders as a result of changes in taxation laws or in their interpretation or administration (including changes in the administrative practices and assessing policies of the Canada Revenue Agency);

(d) making corrections, or removing or curing any conflicts or inconsistencies between the provisions of this Declaration of Trust or any supplemental agreement and any other agreement of the Trust or any offering document with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustees the rights of the Unitholders are not materially prejudiced thereby;

(e) making amendments hereto as are necessary or desirable for correcting typographical mistakes or for curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions;

(f) making amendments hereto as are required to undertake an internal reorganization of the Trust or its affiliates (and for this purpose an "internal reorganization" means the sale, lease, exchange, transfer or other disposition of the assets of a person, whether or not involving all or substantially all of the assets of such person, as a result of which such person has substantially the same interest, whether direct or indirect, in

such assets that it had prior to the reorganization and, for greater certainty, may include an amalgamation, arrangement or merger of such person and its affiliates with any other entities); or

(g) making amendments hereto for any purpose in addition to those stated above, provided that, in the opinion of the Trustees, the rights of the Unitholders are not materially prejudiced thereby.

Holders of Preferred Units are not entitled to vote in respect of any Special Resolution on an amendment to the Declaration of Trust unless the proposed amendment triggers the limited voting rights of such holders described below under "*Securities of the Trust – Equity Securities – Preferred Units*".

Power of Attorney

Upon becoming a holder of Units, each Unitholder, pursuant to the terms of the Declaration of Trust, grants to the Trustees a power of attorney constituting the Trustees (whether acting individually or collectively), with full power of substitution, as the true and lawful attorney of such Unitholder to act on his behalf, with full power and authority to execute, under seal or otherwise, swear to, acknowledge, deliver, make, file or record (and to take all requisite actions in connection with such matters), when, as and where required: (a) the Declaration of Trust and any other instrument required or desirable to qualify, continue and keep in good standing the Trust as a mutual fund trust in all jurisdictions that the Trustees deem appropriate; (b) any instrument, deed, agreement or document in connection with carrying on the affairs of the Trust; (c) all conveyances, transfers and other documents required in connection with the dissolution, liquidation or termination of the Trust; (d) any and all elections, determinations or designations whether jointly with third parties or otherwise, under the Tax Act or any other taxation or other legislation or similar laws of Canada or of any other jurisdiction in respect of the affairs of the Trust or of a Unitholder's interest in the Trust; (e) any instrument, certificate and other documents necessary or appropriate to reflect and give effect to any amendment to the Declaration of Trust which is authorized from time to time as contemplated by the terms of the Declaration of Trust; (f) all transfers, conveyances and other documents required to deal with Units and/or exchangeable securities of the Trust of non-tendering offerees pursuant to take-over bid, but subject to the provisions respect same as contained in the Declaration of Trust; and (g) any instrument, deed, agreement or document as may be necessary or appropriate in connection with carrying on the business and undertaking of the Trust.

Under the Declaration of Trust, each Unitholder is agreeing that the power of attorney is, to the extent permitted by applicable law, irrevocable and is a power coupled with an interest and shall survive the insolvency, death, mental incompetence, disability and any subsequent legal incapacity of the Unitholder and shall survive the assignment by the Unitholder of all or part of the holder's interest in the Trust and will extend to and bind the heirs, executors, administrators and other legal representatives and successors and assigns of the Unitholder. Each Unitholder agrees to be bound by any representations or actions made or taken by the Trustees pursuant to the power of attorney and waives any and all defences which may be available to contest, negate or disaffirm any actions taken by the Trustees in good faith under the power of attorney. The power of attorney survives and continues not only in respect of the Trustees but also in respect of any successor trustee.

Term of the Trust and Distribution on Wind-Up

The Trust is obligated to commence its wind-up and termination upon the first of the following to occur: (a) a proposal to the holders of Trust Units, by the Administrator, to wind-up and terminate the Trust, which proposal is approved by way of a Special Resolution; or (b) the date upon which each of the material businesses in which the Trust holds an interest, or has otherwise invested, have been liquidated.

ADMINISTRATION AGREEMENT

The Trust has entered into an Administration Agreement with the Administrator pursuant to which the Trustees have delegated to the Administrator the obligation to provide and perform for and on behalf of the Trust most all services that are or may be required or advisable, from time to time, in order to manage and administer the operations of the Trust. The Administration Agreement sets forth all of the rights, restrictions and limitations (including, without limitation, limitations of liability and indemnification rights) which pertain to the performance by the Administrator of the duties delegated to it by the Trustees.

Following is a summary only of certain material provisions of the Administration Agreement, which is qualified in its entirety by the complete text of the Administration Agreement, a copy of which will be available at www.sedar.com under the Trust's profile.

Delegated Responsibility; Services

In accordance with the provisions of the Declaration of Trust, and pursuant to the terms and conditions of the Administration Agreement, the Trust and the Trustees appointed the Administrator as administrator of the Trust, and delegated to the Administrator responsibility for the general administration, management and governance of the affairs of the Trust, and in connection therewith the Administrator is required to provide and perform all administrative, management and governance services (with limited exceptions) as may be required or advisable from time to time in order to administer, manage and govern the operations of the Trust, including the following services:

(a) prepare all returns, filings and documents and make all determinations necessary for the discharge of the Trustees' record-keeping and financial reporting obligations under of the Declaration of Trust;

(b) prepare and cause to be provided to Unitholders on a timely basis all information to which Unitholders are entitled under the Declaration of Trust and under applicable laws, including notices, financial statements and tax information relating to the Trust;

(c) prepare, or cause to be prepared, the annual financial statements of the Trust, as well as relevant tax information, which are to be provided to Unitholders;

(d) select, engage and/or appoint such bank, trust company or other firm or corporation carrying on banking business, as is determined in the discretion of the Administrator, for purposes of having the Trust carry on its banking and banking related activities therewith;

(e) open, operate and close accounts and make other similar credit, deposit and banking arrangements and to negotiate and sign banking and financing contracts and agreements;

(f) compute, determine, declare and direct distributions (if any) to Unitholders and, in connection therewith, withhold (or advise the Trustees to withhold) all amounts required by applicable tax laws, and make all such remittances and filings (or advise the Trustees to make all such remittances and filings) in connection with such withholdings;

(g) determine the amount of distributable cash and other amounts requiring determination pursuant to the terms of the Declaration of Trust;

(h) ensure compliance by the Trust with all applicable laws, including without limitation, securities legislation and related regulation;

(i) provide investor relations services to the Trust;

(j) arrange for and hold any meetings of Unitholders as may be called pursuant to the Declaration of Trust, and prepare, approve and arrange for the distribution of all such materials (including notices of meetings and information circulars) in respect thereof;

(k) attend to all administration and other matters arising in connection with any Unit redemptions;

(l) monitor the Trust's status as a "mutual fund trust" within the meaning of the Tax Act, and provide the Trustees with written notice when the Trust is at risk of ceasing to be a mutual fund trust;

(m) monitor the status of the Units as to their eligibility for investment through tax-exempt plans;

(n) undertake and perform all acts, duties and responsibilities in connection with acquiring or disposing of assets and property, for and on behalf of the Trust, of whatsoever nature or kind;

(o) advise the Trustees with respect to matters in connection with the issue, sale or pledge of debt obligations or guarantees of the Trust, whether secured or unsecured, including establishing credit facilities or other borrowing arrangements, as required;

(p) advise the Trustees with respect to matters in connection with, or for the purpose of completing, any securities offerings from time to time, including with respect to the following matters: (i) determining the timing and terms of such offerings; (ii) preparing any offering document (and any amendments thereto); (iii) preparing all agreements relating to the acquisitions of, or other investments in, the assets and other properties that will comprise the Trust's property, and all instruments, contracts and other documents requiring execution by the Trust in connection with any offering;

(q) preparing such other contracts, documents, instruments and agreements as may be necessary or desirable in connection with any offering;

(r) advise the Trustees with respect to the timing and terms of any offer by the Trust for, and repurchase by the Trust of, previously issued Units and other securities of the Trust;

(s) advise the Trustees with respect to matters in connection with the establishment, implementation and amendment (when and as required, once established) of any distribution reinvestment plans, Unit purchase plans, and incentive option and other compensation plans as may be determined to be desirable for the Trust to establish;

(t) attend to all matters in connection with the administration of the operation of any Unitholder rights plan, distribution reinvestment plans, Unit purchase plans, incentive option and other compensation plans as may be established by the Trust from time to time;

(u) exercise, in respect of all matters properly construed as having been delegated to the Administrator hereunder, the discretion which the Trustees are otherwise permitted to exercise under the Declaration of Trust in respect to such matters;

(v) prepare, approve, execute and deliver, on behalf of the Trust, such agreements, including exchange agreements and exchangeable security support agreements, as may be necessary or desirable to properly provide for the terms of exchangeable securities, including coattail provisions for Units in the event of a non-exempt take-over bid for the exchangeable securities and the conversion, exercise, redemption or exchange of such exchangeable securities for Units (including the conditional and automatic conversion, exercise, redemption or exchange of such exchangeable securities in the event of a take-over bid for the Units);

(w) engage (including negotiate contracts with) and oversee third party providers of services to Trust (including transfer agents, legal counsel, financial advisors, auditors and printers) in connection with provision of the Services;

(x) undertake all matters in connection with any take-over bid, merger, amalgamation, arrangement, reorganization, recapitalization, purchase or repurchase of any securities or assets of any person, any business combination, or any other similar transaction involving the Trust (the foregoing individually referred to as a "Transaction" and collectively as the "Transactions"), including, without limiting the generality of the foregoing, the right, power and authority to: (i) establish, implement and amend (when and as required, once established) any Unitholder rights plan as the Administrator may determine to be desirable for the Trust to establish; (ii) issue news releases and ensure compliance by the Trust with its continuous disclosure obligations under all applicable securities legislation; (iii) provide or arrange for the provision of investor relations services to the Trust;

(y) approve, prepare or cause to be prepared, and send or cause to be sent to Unitholders, any circular or other disclosure documents (and all amendments thereto) required under applicable securities legislation in response to any offer for the Units;

(z) call, hold, and prepare or cause to be prepared, all materials (including notices of meetings and information circulars) in respect of all special meetings of Unitholders required or desirable in connection with any Transaction;

(aa) make all determinations, enter all agreements, prepare all documents and take all other actions with respect to any Transaction which may be determined by the Administrator to be necessary, expedient, desirable or advisable for the best interests of the Trust and its Unitholders, and so as to comply with all Applicable Laws; and

(bb) generally provide all other services as may be required or desirable in the opinion of the Administrator for the administration, management or governance of the Trust and which are not otherwise expressly delegated to the Administrator under the terms of the Declaration of Trust or the foregoing clauses.

For certainty, the Administration Agreement confirms that the Administrator's services include performance of those duties, and the exercise of those rights, referred to in the Declaration of Trust as being exercisable by, attributable to, or the responsibility of, the Administrator.

Limitation of Liability

In general, the Administrator's liability will be limited, and it will be entitled to indemnification from the Trust, in respect of demands, claims and liabilities of any nature provided that the Administrator has acted honestly and in good faith.

Permitted Interests

The Administrator and its directors and officers, as well as their respective affiliates and associates, are permitted to have business and other interests or associations of whatever nature or kind apart from their activities related to the Trust. The Trust and the Administrator have each acknowledged that there are and will continue to be potential or actual interests of the Administrator and its management (or their respective associates or affiliates), including conflicts of interest, with respect to interests held by, and/or contractual arrangements or transactions involving, one or more of the Administrator, the Administrator's management, the Trust or the Trustees, and any of the respective affiliates and associates of any of them, and the Trust has agreed that interests of the Administrator or the Administrator's management (or their respective associates or affiliates), including any conflicts of interest, will not form the basis for any claim against the Administrator, the Administrator's management or any respective affiliate or associate thereof, or their respective shareholders, directors, officers or employees, or for any attempt to challenge or attack the validity of any contract, transaction or arrangement (or renewal, extension or amendments of same), in each case, provided that the Administrator has otherwise exercised its powers and discharged its duties under the Administration Agreement honestly and in good faith.

Termination and Removal of Administrator

The Administration Agreement remains in effect until wind-up and dissolution of the Trust unless earlier terminated by the mutual agreement of the Administrator and the Trust. The Administrator may only be removed as administrator of the Trust in the following circumstances: (a) the Administrator or a majority of its directors have been convicted of fraud or embezzlement; (b) the Administrator (i) files a voluntary petition in bankruptcy or makes any assignment for the benefit of creditors of the Administrator, (ii) is involuntarily dissolved and commences its winding-up, or (iii) consents to or acquiesces to the appointment of a trustee, receiver or liquidator of the Administrator; (c) the following has been commenced against the Administrator (i) the institution of any proceeding or the taking of any action seeking to adjudicate it bankrupt or insolvent or seeking liquidation, dissolution, winding-up, reorganization or protection of its property, (ii) the making of a proposal with respect to it under any law related to bankruptcy, insolvency, reorganization or other similar law, or (iii) the seeking of the appointment of a receiver, trustee, agent or other similar official for it for a substantial part of its assets, provided that any such proceeding, petition or action under this paragraph (c) has been commenced against the Administrator or any of its assets by a *bona fide* party and is not stayed, vacated or dismissed within 90 days; or (d) the Administrator has breached any of its material covenants or obligations under the Administration Agreement and such breach is not cured within 60 days (or is in the process of being cured within 60 days and is not cured within 120 days) of the Trust formally

notifying the Administrator of such default. Upon the occurrence of one of the defaults set forth above, the Trust Unitholders may remove the Administrator if such removal is first approved by a Special Resolution of Trust Unitholders. The Special Resolution must state the planned effective date of the removal of the Administrator, and such removal shall only take effect, notwithstanding the Special Resolution, once the following has occurred: (i) the full and unconditional release of the Administrator and its affiliates or associates (as the case may be) is obtained in respect of any mortgage or other indebtedness, liability or obligation of the Trust to which they are subject; and (ii) the payment of all money owing by the Trust to the Administrator and its affiliates and associates.

Remuneration

There is no fee payable to the Administrator under the terms of the Administration Agreement but the Administrator will be entitled to the reimbursement of all costs and expenses reasonably incurred by the Administrator in carrying out its obligations and duties under the Administration Agreement, including payroll and payroll related costs, overhead, general and administrative costs, and out-of-pocket and third party fees and expenses.

LIMITED PARTNERSHIP AGREEMENT

The Trust, as initial limited partner, and the General Partner, as general partner, entered into a Limited Partnership Agreement dated January 22, 2010 which provides for the terms and conditions governing the Partnership. Following is a summary only of certain material provisions of the LP Agreement, which is qualified in its entirety by the complete text of the LP Agreement, a copy of which will be available at www.sedar.com under the Trust's profile.

Distributions from the Partnership

Holders of LP Units (which includes the Trust) are entitled to receive non-cumulative distributions if, as and when declared by the General Partner. It is within the General Partner's sole discretion to determine the utilization of available cash flow from the business and operations of the Partnership for matters beyond satisfying all mandatory liabilities and other payment obligations of the Partnership. Any amount that is to be distributed among Limited Partners will be apportioned among them pro-rata based upon the number of LP Units held.

Management and Control of the Partnership

Subject to the Partnership Act and to the limitations expressly set forth in the LP Agreement, the General Partner (which is wholly-owned by the Trust) will have exclusive authority to direct and manage the affairs of the Partnership, with full power and authority to administer, manage, control and operate the business carried on by the Partnership and to do any act, take any proceedings, make any decisions and execute and deliver any instrument, deed, agreement or document necessary for or incidental to carrying on the business of oil and gas exploration and production. The LP Agreement provides that the General Partner must act honestly, in good faith and in the best interests of the Partnership and, in connection therewith, exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

Removal of General Partner

The General Partner may only be removed as the general partner of the Partnership in the following circumstances: (a) the General Partner (i) files a voluntary petition in bankruptcy or makes any assignment for the benefit of creditors of the General Partner, or (ii) consents to or acquiesces to the appointment of a trustee, receiver or liquidator of the General Partner; (b) the following has been commenced against the General Partner (i) the institution of any proceeding or the taking of any action seeking to adjudicate it bankrupt or seeking liquidation, dissolution, winding up, reorganization or protection of its property, (ii) the making of a proposal with respect to it under any law related to bankruptcy, insolvency, reorganization or other similar law, or (iii) the seeking of the appointment of a receiver, trustee, agent or other similar official for it for a substantial part of its assets, provided that any such proceeding, petition or action under this paragraph (b) has been commenced against the General Partner or any of its assets by a *bona fide* party and is not stayed, vacated or dismissed within 90 days; or (c) the General Partner has breached any of its material covenants or obligations under the LP Agreement and such breach is not cured within 60 days of a Limited Partner formally notifying the General Partner of such default or, if such

breach is not reasonably remediable with such 60 day period the General Partner fails to commence within such 60 day period to take steps to remedy such default and to thereafter proceed diligently to cure the default.

Upon the occurrence of one of the general partner defaults set forth above, the Limited Partners may remove the General Partner by passage of a special resolution of the Limited Partners in favour of such removal, provided such special resolution shall only be effective if it includes provision for the appointment of a substitute general partner of the Partnership to be appointed concurrent with the removal of the General Partner. The Limited Partners must provide the General Partner with written notice stating the planned effective date of the removal, provided that the removal of the General Partner shall only take effect, notwithstanding the special resolution, once the following has occurred: (i) the full and unconditional release of the General Partner and its affiliates or associates (as the case may be) is obtained in respect of any mortgage or other indebtedness, liability or obligation of the Partnership to which they are subject; (ii) the payment of all money owing by the Partnership to the General Partner, and (iii) where the General Partner being removed is affiliated to the Trust, the repayment in full of all outstanding indebtedness of the Partnership to the Trust, howsoever and whensoever incurred.

Reimbursement of General Partner

The Partnership will reimburse the General Partner, when and as invoiced, for all direct and indirect operating, general and administrative costs and expenses, as well as other costs and expenses whatsoever, that the General Partner or its affiliates or associates incur which are related to or in connection howsoever with the operation and conduct of the business and affairs of the Partnership.

Business Interests of the General Partner

The LP Agreement provides that both the General Partner and its directors and officers as well as their respective affiliates and associates, are permitted to have business and other interests or associations of whatever nature or kind apart from their activities related to the Partnership's business, including business and other interests or associations which consist of oil and gas exploration and production. Directors and officers of the General Partner currently have, and may in the future have, other business interests and associations consisting of oil and gas exploration and production.

Under the LP Agreement, Limited Partners acknowledge that there are and will continue to be potential or actual interests of the management of the General Partner (or their associates or affiliates), including conflicts of interest, with respect to business or other interests held directly or indirectly by, and/or contractual arrangements or transactions directly or indirectly involving, one or more of, the Partnership, the General Partner (and its directors and officers) or any of the respective affiliates and associates of any of them, and the Limited Partners agree that (a) interests of the General Partner or any of its directors or officers or their respective associates or affiliates ("**Interested Persons**"), including any conflicts of interest, will not form the basis for any claim against the General Partner (and its directors and officers) or any respective affiliate or associate thereof, or their respective shareholders, directors, officers or employees, nor will they form the basis for any attempt to challenge or attack the validity of any contract, transaction, arrangement or payment (or renewal, extension or amendments of same), and (b) any Interested Person is expressly permitted to derive direct or indirect benefit, profit or advantage from time to time as a result of dealing with the Partnership or its affiliates or as a result of the relationships, matters, contracts, transactions, affiliations or other interests it may have and such Interested Person shall not be liable in law or in equity to pay or account to the Partnership, or to any Unitholder for any such direct or indirect benefit, profit or advantage nor, in such circumstances, will any contract or transaction be void or voidable at the instance of the Partnership, Unitholder or any other person; provided, in each case, that the General Partner has otherwise exercised its powers and discharged its duties under the LP Agreement honestly and in good faith in respect to the matter, contract, transaction or interest in question.

The General Partner may employ or retain, on behalf of the Partnership, an affiliate or associate of the General Partner or any of its directors or officers to provide goods or services to the Partnership, provided that the terms of such agreements or contracts are no less favourable to the Partnership than those that would be obtained from an independent third party.

Allocation of Income and Loss

The LP Agreement provides that the net income or net loss of the Partnership (as the case may be) for each fiscal year, as well as its income or loss from a particular source or a source in a particular place, and the capital gains and capital losses, shall each be allocated among the Limited Partners pro-rata in proportion to the number of LP Units held by each of them at the end of such fiscal year.

LP Units and Other Securities

The Partnership is authorized to issue an unlimited number of LP Units, each of which has the rights, privileges, restrictions and conditions set forth in the LP Agreement. The General Partner, in its sole discretion, may issue additional LP Units and any other securities of the Partnership (including debt securities), from time to time, to any person where it is necessary or desirable in connection with the conduct of the business of the Partnership, and in each case such securities may be issued at such prices and upon such terms and at such time or times as the General Partner may determine provided that any such issuance is subject to pre-emptive rights in favour of each of the current Limited Partners of the Partnership (including the Trust).

Distributions on Dissolution

Upon the dissolution of the Partnership, the net proceeds from the liquidation of the assets of the Partnership will be distributed in the following order of priority: (a) to pay the expenses of liquidation and the debts and liabilities of the Partnership to its creditors; and then (b) to provide for such reserves as the receiver considers reasonably necessary for any contingent or unforeseen liabilities or obligations of the Partnership; and then (c) to pay to the General Partner the amount of its capital account balance together with the amount of any costs and expenses that the General Partner is entitled to receive from the Partnership; and (d) to pay to the Limited Partners the balance of the net proceeds on a pro rata basis in accordance with the number of LP Units held by the Limited Partners.

SECURITIES OF THE TRUST

Equity Securities

The Trust is currently authorized to issue two classes of equity securities – being Trust Units and Preferred Units.

The only outstanding Units are Trust Units, of which 1,109,731,962 are currently issued and outstanding. There are no Preferred Units outstanding.

Trust Units

The Trust Units are equity securities to which are attached the following principal rights, privileges, restrictions and conditions as provided in the Declaration of Trust:

- Voting Rights. Holders of Trust Units are entitled to receive notice of and to attend all meetings of unitholders of the Trust and to one (1) vote in respect of each Trust Unit held at all such meetings, except for meetings of holders of Preferred Units only. See "*Declaration of Trust – Meetings of Unitholders*".

- Distributions. Holders of Trust Units are entitled to receive non-cumulative distributions only if, as and when declared by the Trustees in accordance with the provisions of the Declaration of Trust. See "*Declaration of Trust – Distribution Rights; Distributable Cash*", "*Distribution Policy*" and "*Risk Factors*".

- Redemption. Trust Units are redeemable on demand by the holders thereof, at a redemption price based on 90% of the fair market value as determined by the Administrator or, if the Trust Units are listed, traded or quoted on a stock exchange or market at the relevant time, the lesser of 90% of their "market price" or 100% of their "closing market price", subject to certain limitations on payment of the redemption price and the consideration therefor. See "*Declaration of Trust – Redemption Rights*".

- Liquidation, Dissolution or Winding Up. Holders of Trust Units are entitled to share rateably in any distribution of the remaining assets of the Trust in the event of the liquidation, dissolution or winding up of the Trust or other distribution of Trust assets among its unitholders for the purpose of winding up its affairs, subject to the rights of the holders of any other class of units entitled to receive assets of the Trust upon such a distribution in priority to, or concurrently with, holders of Trust Units.

No distributions have been declared or paid on the Trust Units since January 1, 2012. See "*Declaration of Trust – Distribution Rights; Distributable Cash*", "*Distribution Policy*" and "*Risk Factors*".

Preferred Units

The Preferred Units are generally non-voting securities except in the limited circumstances provided for under the Declaration of Trust (see "*Declaration of Trust – Meetings of Unitholders*"), and confer upon the holders thereof a preference over the holders of Trust Units with respect to distributions and participation in a liquidation, dissolution or winding-up, and are subject to redemption and conversion, as follows:

- Distributions. Holders of Preferred Units have preferential rights to (i) to the extent distributable cash is available, a fixed, preferential cumulative distribution at the rate of $0.1025 per Preferred Unit per annum (adjusted for any portion of the distribution period during which the unit was not outstanding), and (ii) in the event of a distribution of distributable cash in excess of unpaid amounts in respect of declared distributions on the Preferred Units (to the extent not already taken into account in calculating distributable cash), an equal proportionate 10% share thereof up to a maximum additional amount (above the fixed annual amount of $0.1025) of $0.0175 per Preferred Unit per annum. See "*Declaration of Trust – Distribution Rights; Distributable Cash*".

- Redemption. Preferred Units are redeemable on demand by the holders thereof, at a redemption price based on 90% of the fair market value as determined by the Administrator or, if the Preferred Units are listed, traded or quoted on a stock exchange or market at the relevant time, the 90% of their "market price" or 100% of their "closing market price", subject to certain limitations on payment of the redemption price and the consideration therefor. In addition, the Trust may at its election redeem Preferred Units at a cash redemption price per Preferred Unit based on the aggregate gross proceeds from the issuance of all Preferred Units issued since formation of the Trust and still outstanding. See "*Declaration of Trust – Redemption Rights*".

- Conversion. The Preferred Units are convertible to Trust Units, at the option of the Trust, on not less than 30 days' written notice, at a conversion ratio determined according to the formula set forth in the Declaration of Trust. That formula is primarily a function of (i) the aggregate gross proceeds from the original issue by the Trust of all Preferred Units being converted, and (ii) the deemed equity value of the Trust Units based on the consolidated net income of the Trust for and in respect of the two financial quarters preceding the date of conversion (provided that the most recent such quarter ended at least 45 days before the conversion date), as adjusted in accordance with the provisions of the Declaration of Trust. Any outstanding Preferred Units will also automatically convert into Trust Units in certain events. See "*Declaration of Trust – Conversion of Preferred Units to Trust Units*".

- Liquidation, Dissolution or Winding Up. In the event of the liquidation, dissolution or winding up of the Trust or other distribution of Trust assets among its unitholders for the purpose of winding up its affairs, each holder of Preferred Units is entitled to receive from the assets of the Trust, for and in respect of each Preferred Unit held, before any amount is paid or any Trust property is distributed to any holder of Trust Units or units of any other class ranking junior to the Preferred Units, the sum of (a) the quotient obtained when the aggregate gross proceeds from the issuance of all Preferred Units issued since formation and still outstanding is divided by the aggregate number of Preferred Units issued and outstanding; plus (b) all accumulated and unpaid distributions in respect of such Preferred Unit (if any). After payment or distribution of such sum, holders of Preferred Units shall not participate any further in any further distribution of the remaining assets of the Trust.

Since January 1, 2012, aggregate cash distributions of $0.2033 per unit have been made to the holders of previously-outstanding Preferred Units in accordance with the priority distribution rights attached thereto. For purposes of the Tax Act all such distributions constituted returns of capital.

During the 12-month period preceding the date hereof, the Trust issued an aggregate of 615,573.9 Preferred Units at an issue price of $1.00 per unit pursuant to the DRIP, with issuances effective December 31, 2014 (as to 309,362.22 units) and March 31, 2015 (as to 306,211.68 units).

Prior to June 21, 2015 there were approximately 33.8 million Preferred Units outstanding. On May 22, 2015, the Trust issued a notice of conversion to the holders of the outstanding Preferred Units pursuant to which, in accordance with the Declaration of Trust, all outstanding Preferred Units were converted to Trust Units effective June 21, 2015 on the basis of approximately 32.6 Trust Units for every one (1) Preferred Unit. See "*Declaration of Trust – Conversion of Preferred Units to Trust Units*". As a consequence of that conversion, there are no Preferred Units left outstanding and the former holders of Preferred Units (as a group) hold approximately 99.5% of the outstanding Trust Units.

Debt Securities

As at the date hereof, the only outstanding debt securities of Petrocapita (other than debt securities of the Administrator or Partnership that are held by the Trust) are two secured debentures issued in June 2015, in principal amounts of $460,000 and $217,000, respectively, to the vendors of certain assets acquired by Petrocapita. See "*General Development of the Business – 2015*". Both are secured by the assets acquired, bear interest at the rate of 6% per annum (payable monthly) and have a 7-year term maturing in June 2022.

The holder of the $460,000 debenture due June 1, 2022 may elect to capitalize interest as additional principal in lieu of receiving the interest payment.

If the Trust Units become listed on a qualified stock exchange or market, the principal amount of the $217,000 debenture due June 30, 2022 is convertible at the holder's election into Trust Units at a conversion price per unit equal to a 20-day volume-weighted average price of the Trust Units on the applicable exchange or market (provided that such price is not less than the minimum issue price permitted under applicable stock exchange or market rules).

Options, Warrants or Other Convertible Securities

Except for the $217,000 convertible debenture described above under "*– Debt Securities*", there are no outstanding options, warrants or other convertible securities entitling the holder thereof to purchase or otherwise acquire Trust Units or any other securities of the Trust, the Administrator or the Partnership.

Change in Consolidated Capitalization

There has been no material change in the consolidated unit and loan capital of the Trust since June 30, 2015, being the date of the most recently completed financial period for which financial statements are included at Appendix A.

Market for Trust Securities

There is currently no market through which any securities of the Trust may be sold, and holders may not be able to resell securities of the Trust previously acquired by them. This may affect the pricing of the Trust's securities in the secondary market, the transparency and availability of trading prices, the liquidity of the Trust's securities and the extent of issuer regulation.

The Trust Units are not listed or quoted, and no application has been made to list or quote the Trust Units, on any exchange or marketplace.

In the event that the Trust Units (or any other securities of the Trust) become listed on a stock exchange or other "public market" within the meaning of the applicable provisions of the Tax Act, the Trust will become a "specified investment flow-through" (SIFT) trust for purposes of the Tax Act, which will result in the Trust becoming liable to

pay income tax at the entity level in respect of certain of its distributions at a rate substantially equivalent to the combined federal and provincial corporate tax rate applicable to taxable Canadian corporations. See "*Taxation of Specified Investment Flow-Through Trusts*".

TAXATION OF SPECIFIED INVESTMENT FLOW-THROUGH TRUSTS

The Trust is currently generally entitled to deduct distributions to Unitholders in computing its taxable income for Canadian income tax purposes. If, however, the Trust Units (or any other securities of the Trust) become listed on a stock exchange or other "public market" within the meaning of the applicable provisions of the Tax Act, the Trust will become a "specified investment flow-through" (SIFT) trust for purposes of the Tax Act, which will result in the Trust becoming liable to pay income tax at the entity level in respect of certain distributions that are attributable to the Trust's "non-portfolio earnings" (as discussed below) at a rate substantially equivalent to the combined federal and provincial corporate tax rate applicable to taxable Canadian corporations.

Historically, neither the Trust nor any of its subsidiaries have been liable for amounts of income tax under the Tax Act as Petrocapita's oil and gas activities have generated cost and resource pools that are deductible against income in amounts that have been sufficient in magnitude to offset income that would otherwise be subject to Canadian tax. Such pools include acquisition costs, drilling and completion costs and other costs that constitute "Canadian oil and gas property expense" (COGPE), "Canadian development expense" (CDE), "Canadian exploration expense" (CEE) and capital cost allowance (CCA) within the meaning of the Tax Act.

Becoming a SIFT trust would not affect the availability to Petrocapita of tax-deductible pools arising from oil and gas activities, but would restrict its ability to deduct amounts paid or made payable to Unitholders in computing the taxable income of the Trust.

The taxation year of the Trust is currently a calendar year. For so long as it is not a SIFT trust, the Trust will be subject to tax under Part I of the Tax Act on its net income for the year (including any net taxable capital gains) less the portion thereof that it deducts in respect of amounts paid or payable in the year to Unitholders. An amount will be considered to be payable to a Unitholders in a taxation year if it is paid to the Unitholder in the year by the Trust or if the Unitholder is entitled in that year to enforce payment of the amount. Whether a deduction for amounts paid or payable in the year to Unitholders is necessary to eliminate taxable income in the Trust will depend on whether the Trust otherwise has available resource pools and other deductible amounts that are sufficient to shelter income that would otherwise be subject to income tax.

If the Trust becomes a SIFT trust, it will no longer be able to deduct any part of the amounts payable to Unitholders in respect of its "non-portfolio earnings", which will include: (i) income (other than income that is a taxable dividend received by the Trust) from its "non-portfolio properties" (exceeding any losses for the taxation year from such properties); and (ii) taxable capital gains from dispositions of non-portfolio properties (exceeding allowable capital losses from the disposition of such properties).

For this purpose, "non-portfolio property" includes: (i) certain Canadian real and resource properties; (ii) a property that the Trust (or a non-arm's length person or partnership) uses in the course of carrying on a business in Canada; and (iii) "securities" of a "subject entity" (other than a "portfolio investment entity") if the Trust holds securities of the subject entity that have a total fair market value that is greater than 10% of the subject entity's equity value or if the Trust holds securities of the subject entity which, together with all securities held of affiliates of the subject entity, have a total fair market value that is greater than 50% of the Trust's equity value. A "subject entity" includes corporations resident in Canada, trusts resident in Canada, and "Canadian resident partnerships", all within the meaning of the Tax Act. Petrocapita anticipates that substantially all of its assets would constitute "non-portfolio property" and that substantially all of its earnings from ordinary business operations would constitute "non-portfolio earnings", such that any distributions to Unitholders from out of such earnings would not, if the Trust becomes a SIFT trust, be deductible in computing its taxable income.

Taxable income that the Trust is unable to shelter through its cost and resource pools or which it does not otherwise distribute to Unitholders will be subject to tax under Part I of the Tax Act. Any such tax liability will necessarily reduce net amounts that would otherwise be available for reinvestment in Petrocapita's business or potential distribution to Unitholders.

A trust that becomes a SIFT trust at any time during a taxation year will be deemed to have been a SIFT trust throughout the year.

The taxability of distributions in the hands of Unitholders will also vary according to whether the Trust is (or is deemed to be) a SIFT trust at the relevant time. In the case of a trust that is not a SIFT trust or in the case of distributions that the Trust deducts in computing its income (i.e., distributions that are not attributable to "non-portfolio earnings"), a Unitholder that is not exempt from tax under Part I of the Tax Act will generally be required to include in income for a particular taxation year the portion of the net income of the Trust (including net realized capital gains) that is paid or payable to the Unitholder in the year, whether that amount is paid in cash, additional trust units or other property. In the case of a SIFT trust, distributions attributable to non-portfolio earnings to non-exempt Unitholders will generally be taxed as dividends from a taxable Canadian corporation, which will be subject to the "gross-up and dividend tax credit" provisions of the Tax Act for individual Unitholders and treated as an "eligible dividend" if paid to a resident of Canada. Any such distributions received by a corporation will be included in computing the corporation's income and will generally be deductible in computing its taxable income. A corporation that is a "private corporation" or a "subject corporation", each as defined in the Tax Act, may be liable under Part IV of the Tax Act to pay a refundable tax at a rate of 33% on such dividends to the extent that such dividends are deductible in computing the corporation's taxable income.

The SIFT rules do not change the tax treatment of distributions that are in excess of a trust's taxable income. For a SIFT trust, any amount paid or payable (or deemed paid or payable) to non-exempt unitholders in a taxation year that is in excess of the trust's "taxable non-portfolio earnings" will not generally be included in the unitholder's income for the year. Instead, the unitholder will be required to reduce the adjusted cost base of its units for income tax purposes, and will realize a net capital gain to the extent that the adjusted cost base would otherwise be a negative amount. In the event such a gain is realized, the adjusted cost base of the units to the unitholder will then be reset to nil.

DISTRIBUTION POLICY

The Trust may in the future make distributions of available funds to holders of Trust Units, but has no obligation to do so. Holders of Trust Units are entitled to receive non-cumulative distributions only if, as and when declared by the Trustees in accordance with the provisions of the Declaration of Trust. **Any such distributions are discretionary and there is no assurance that they will be declared on a regular or consistent basis or at all.** See "*Declaration of Trust – Distribution Rights; Distributable Cash*".

The Trustees will determine whether to declare and pay cash distributions from out of the distributable cash of the Trust, if any, based on its financial position at the relevant time, which will in turn depend on Petrocapita's earnings and obligations (including the effect of commodity prices, production levels, operating costs, royalty and tax burdens, capital expenditure requirements, current and potential future environmental liabilities, debt service requirements, covenants and obligations, interest rates and/or foreign exchange rates, growth of the general economy, the price of crude oil and natural gas, and the number of Trust Units issued and outstanding) as well as decisions of the Board and Management of the Administrator and General Partner regarding reinvestment in Petrocapita's oil and gas operations and business generally.

In the near term, based on current commodity price and cost forecasts, Petrocapita does not anticipate making cash distributions on the Trust Units but instead reinvesting available cash flows in its business. As commodity prices recover, Petrocapita anticipates returning to a sustainable distribution profile that balances the objectives of providing holders of Trust Units with relatively stable and predictable distributions while at the same time retaining a portion of cash flow to fund acquisition, development and optimization projects that aim to enhance the overall value of Petrocapita's business and the sustainability of its cash flows.

The Trustees have not established a target distribution level or determined what amount, if any, will likely be distributed to holders of Trust Units in the next twelve months.

See also "*Risk Factors*".

PRINCIPAL UNITHOLDERS

The only outstanding Units are Trust Units, of which 1,109,731,962 are currently issued and outstanding. To the knowledge of the Trustees and directors and executive officers of the Administrator, no person or company beneficially owns or controls or directs, directly or indirectly, more than 10% of the issued and outstanding Trust Units.

TRUSTEES, DIRECTORS AND EXECUTIVE OFFICERS

The following table sets out the names of the Trustees and directors and executive officers of the Administrator, their jurisdictions of residence, their positions and offices with Petrocapita and the periods during which they have served in such capacities, and their principal occupations during the five proceeding years.

Name and Jurisdiction of Residence	Current Position with Petrocapita	Trustee, Director or Officer Since	Principal Occupation During Last Five Years
Alex Lemmens [(1)(2)] Alberta, Canada	President and Chief Executive Officer and Chairman of the Board	March 2015 (officer) April 2015 (Trustee and director)	President of Birchwood Resources Inc., a private oil and gas exploration and development company with properties in Alberta and Saskatchewan (2010-current).
Richard Mellis [(2)] Alberta, Canada	Vice President, Land and Environment and a Director	January 2014 (officer and director) April 2015 (Trustee)	Vice President, Land and Environment of the Administrator since January 2014. Prior thereto, consultant providing land, environment and regulatory management services to the Administrator (since 2013), Birchwood Resources Inc. (2012-2014), Canadian Coyote Energy Trust (2012-2014), Taku Gas Limited (2011-2014), Linklater Energy Ltd. (2010-2012), Eagle Rock Exploration Ltd. (2010-2012) and Overlord Financial Inc. (2010-2012).
Evelyn Studer Alberta, Canada	Vice President, Finance and Chief Financial Officer	January 2012 [(3)]	Vice President, Finance and Chief Financial Officer of the Administrator since April 2015. Prior thereto, Controller of the Administrator since January 2012. Prior thereto, Chief Financial Officer of Dodsland Oil Processors Ltd. (2010-2012), Controller of Neo Exploration Inc. (2011), Chief Financial Officer of Vertex Oil & Gas Ltd. (2010-1011) and Controller of Harness Petroleum Inc. (2010).
Greg Marr [(1)(2)] Alberta, Canada	Director	April 2015	President of Montage Resources Ltd., a financial management company specializing in oil and gas exploration and development companies in Western Canada. Prior thereto, Financial Consultant or Chief Financial Officer of each of Petro Viking Inc. (2014), West Isle Energy Inc. (2008-2011), Touchstone Exploration Inc. and Seair Inc. (2006-2014).
Ben Van Rootselaar [(1)(2)] Alberta, Canada	Director	April 2015	Consulting Engineer with Tower Ridge Enterprises Corporation, an engineering and management company specializing in oil and gas development exploration and development companies in Western Canada (1995-current).

Notes:

(1) Messrs. Marr (Chair), Van Rootselaar and Lemmens are anticipated to be the members of the Audit Committee.
(2) Messrs. Lemmens, Mellis, Marr and Van Rootselaar also serve as Trustees.
(3) Ms. Studer was appointed in April 2015 to the offices of Vice President, Finance and Chief Financial Officer, and prior to that time served as Controller of the Administrator since January 2012.

As of the date hereof, the Trustees and directors and executive officers of the Administrator, as a group, beneficially own or control or direct, directly or indirectly, an aggregate of 742,924 Trust Units (representing less than 0.1% of the Trust Units outstanding as of the date of this prospectus).

Each director's term of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the ABCA. The officers of the Administrator are appointed by and serve at the discretion of the Board of Directors.

Biographies

Alex Lemmens, P.Eng. – President, Chief Executive Officer and Chairman; Trustee and Director

Mr. Lemmens is the President and Chief Executive Officer of the Administrator, a Trustee and a director and Chairman of the Board. A registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta, Mr. Lemmens has over 40 years' experience of senior management, production operations, drilling, optimization, reserves evaluation and economic analysis in the oil and gas industry. Mr. Lemmens was co-founder of Crucible Resources Inc., a medium oil production company in Saskatchewan, and of Birchwood Resources Inc., a private oil and gas exploitation company with a steam-assisted gravity drainage project in the Bonnyville area and a heavy oil play in Saskatchewan recently sold to Husky Energy Inc. As a senior oil and gas executive, Mr. Lemmens is experienced in the assembly and review of financial information and financial reporting matters, particularly with respect to oil and gas operations, and he has worked extensively with professionals directly responsible for the preparation and audit of financial statements in accordance with applicable accounting standards.

Richard Mellis – Vice President, Land and Environment; Trustee and Director

Mr. Mellis is Vice President, Land and Environment of the Administrator and has over 25 years of experience in the oil and gas industry. Previous to Petrocapita he worked in the land, environmental and regulatory departments of various oil and gas companies and trusts. Mr. Mellis has served as vice president of land and environment for a number of junior oil and gas companies that were subsequently listed on public stock exchanges. Mr. Mellis has been involved in numerous oil and gas acquisition and disposition transactions and drilling projects.

Evelyn Studer – Vice President, Finance and Chief Financial Officer

Ms. Studer is Vice President, Finance and Chief Financial Officer of the Administrator. She is a Certified General Accountant with over 15 years of experience in the oil and gas industry after starting her career at Startech Energy Inc. in 1998. Since then she has worked at a number of energy companies in increasingly senior financial and accounting roles, including Arc Energy Trust, Olympia Energy Inc., Tusk Energy Corporation, True Energy Trust, Harness Energy LLC and Neo Exploration Inc. Ms. Studer holds a Business Administration diploma from Red River College in Winnipeg and a Bachelor of Accounting Science degree from the University of Calgary, and obtained her Certified General Accounting designation in 2005.

Greg Marr – Trustee and Director

Mr. Marr is a Trustee and a director of the Administrator. He is a Chartered Accountant and has over 25 years of experience in the oil and gas industry having worked with various private and public companies in the sector. Mr. Marr is President of Montage Resources Inc., a financial management company specializing in oil and gas exploration and development companies in Western Canada. He has prepared and ensured consistent and compliant disclosure for financial statements, management's discussion and analysis, annual information forms and many other disclosure documents in accordance with GAAP, IFRS and applicable securities laws.

Ben Van Rootselaar, P.Eng. – Trustee and Director

Mr. Van Rootselaar is a Trustee and a director of Petrocapita and, like Mr. Lemmens, is also a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta. He has over with 35 years of diversified engineering and supervisory experience in the oil and gas industry. Mr. Van Rootselaar is President of Tower Ridge Enterprises Corp., an engineering and project management company in oil and gas development, and has been involved in numerous projects including all aspects of operations, facilities, completions, evaluations and joint ventures. Mr. Van Rootselaar is currently working on a joint venture set-up to handle the waste and fluid disposal for a number of steam assisted gravity drainage (SAGD) projects. Mr. Van Rootselaar's

project management and supervisory experience includes the preparation and review of financial information, including in connection with the financial reporting by public companies through annual and interim financial statements and related management's discussion and analysis.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

Except as disclosed below, to the knowledge of Petrocapita, no Trustee or director or executive officer of the Administrator (nor any personal holding company of any of such persons) is, as of the date of this prospectus, or was within ten years before the date of this prospectus, a director, chief executive officer or chief financial officer of any company that: (a) was subject to a cease trade order (including a management cease trade order) ("**CTO**"), an order similar to a CTO or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days, that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to any such order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

During 2007, Greg Marr served as Chief Financial Officer and a director of Landmark Oil & Gas Corp. ("**Landmark**"), Richard Mellis served as Vice President, Land and a director of Landmark, and Ben Van Rootselaar served an independent director of Landmark. Landmark was subject to CTOs issued by the Alberta Securities Commission ("**ASC**") and the British Columbia Securities Commission ("**BCSC**") in May 2007 for failure to file audited annual financial statements for the year ended December 31, 2006. Landmark's audited annual financial statements for the year ended December 31, 2006 and unaudited interim financial statements for the three months ended March 31, 2007 were filed in July 2007, and the CTOs were subsequently revoked by the ASC and the BCSC in September 2007.

Prior to January 2011, Mr. Marr served as Chief Financial Officer and a director of Cromwell Resources Limited ("**Cromwell**"). Cromwell remains subject to CTOs issued by the ASC and the BCSC in May 2007 for failure to file audited annual financial statements for the year ended December 31, 2006. Cromwell's audited annual financial statements for the year ended December 31, 2006 and unaudited interim financial statements for the three months ended March 31, 2007 were filed in August 2007.

Mr. Marr previously served as Chief Financial Officer (prior to October 2011) and a director (prior to June 2011) of Pan Terra Industries Inc. ("**Pan Terra**"). Pan Terra was subject to CTOs issued by the ASC in September 2009 and by the BCSC in October 2009 for failure to file audited annual financial statements for the year ended March 31, 2009 and unaudited interim financial statements for the three months ended June 30, 2009, together in each case with related management's discussion and analysis and officer certifications. The errant filings were completed by Pan Terra in December 2009, and the CTOs were subsequently revoked by the ASC and the BCSC later that month.

Bankruptcies

Except as disclosed below, to the knowledge of Petrocapita, no Trustee or director or executive officer of the Administrator (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust: (a) is, as of the date of this prospectus, or has been within the ten years before the date of this prospectus, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the Trustee, director, executive officer or shareholder.

Greg Marr previously served as Chief Financial Officer and a director of Landmark (until May 2009), Richard Mellis previously served as Vice President, Land and a director of Landmark (until February 2008), and Ben Van Rootselaar previously served an independent director of Landmark (until February 2008). In February 2008, Landmark filed a Notice of Intention to Make a Proposal under the *Bankruptcy and Insolvency Act* (Canada) ("**BIA**"), and in March 2008 submitted a proposal under Part III of the BIA to facilitate an orderly sale and wind-up of operations. The proposal was approved by Landmark's creditors on April 4, 2008 and by the Court of Queen's Bench of Alberta on June 3, 2008. Landmark became inactive after June 3, 2008 and was struck from the Alberta corporate registry in September 2010.

Penalties or Sanctions

To the knowledge of the Trust, no director or executive officer of the Administrator (nor any personal holding company of any of such persons), or Unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain directors and executive officers of the Administrator are also directors and/or officers of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and executive officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors and officers act honestly, in good faith and with a view to the best interests of the Administrator. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director or an officer has an interest in a contract or proposed contract or agreement, the director or officer shall disclose his interest in such contract or agreement and the director shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview

Petrocapita's compensation program is administered by the Board. In addition to its other responsibilities, the Board is responsible for developing and assessing director and executive officer compensation, development and succession. For additional details of the responsibilities, powers and operation of the Board, see "*Corporate Governance*".

Compensation Philosophy and Objectives

Petrocapita believes its success depends on the continued contributions of its executive officers. Petrocapita's executive officers are primarily responsible for its growth and operations strategy, and the management of the day-to-day operations of its subsidiaries. Therefore, it is important to Petrocapita's success that it retains the services of these individuals to ensure Petrocapita's future success.

Petrocapita's overall compensation philosophy is to provide an executive compensation package that enables Petrocapita to attract, retain and motivate executive officers to achieve its short-term and long-term business goals. Petrocapita strives to apply a uniform philosophy regarding compensation of all employees, including members of senior management. This philosophy is based upon the premise that Petrocapita's achievements result from the combined and coordinated efforts of all employees working toward common goals and objectives in a competitive, evolving market place. The goal of Petrocapita's compensation program is to align remuneration with business objectives and performance and to enable Petrocapita to retain and competitively reward executive officers and employees who contribute to Petrocapita's success. In making executive compensation and other employment

compensation decisions, the Board considers achievement of certain criteria, some of which relate to Petrocapita's performance and others of which relate to the performance of the individual employee. Awards to executive officers are based on, among other matters, Petrocapita's achievement and individual performance criteria.

The Board will evaluate Petrocapita's compensation policies on an ongoing basis to determine whether they enable Petrocapita to attract, retain and motivate key personnel. To meet these objectives, the Board may from time to time increase salaries or bonuses or provide other short and long-term incentive compensation to executive officers and other employees.

Elements of Petrocapita's Compensation Program

The elements of the compensation program include base salary commensurate with skills and competency, a cash bonus program based on achieving or exceeding corporate objectives of operational and financial excellence. In the future, the Board may consider adopting stock based compensation arrangements directly relating to management building long term Unitholder value and thereby further aligning interests of management and Unitholders.

The Board believes that the criteria behind Petrocapita's compensation decisions are appropriate and effective to make overall compensation levels competitive to attract and retain quality employees but not excessive or out-of-step with market realities. The compensation of the Chief Executive Officer is based on the same criteria as are applied to the other executive officers of Petrocapita.

Why does Petrocapita choose to pay each element?

Base salary and benefits are generally set at levels required to attract and retain qualified personnel. Annual bonuses are based on meeting or exceeding budgeted plans for operations and financial targets.

How does Petrocapita determine the amount (and, where applicable, the formula) for each element?

Petrocapita's executive compensation program is currently comprised of base salary and annual bonuses as well as typical industry perquisites. All salaries, salary increases and cash bonuses for the executive officers will be reviewed, considered and approved by the Board. There are no formal criteria, objectives or analytics applied to the executive compensation determination.

Base Salary

Base salary is the fixed component of total direct compensation payable to each executive officer. It is intended to attract and retain executives, providing them with a market-competitive level of income certainty. The actual base salary of each will reflect numerous factors relevant to the discharge of their duties, including the complexity of their roles, the amount of applicable industry experience, the function each plays in Petrocapita's development and the need to attract and retain talented individuals. Base salaries will be reviewed and compared to similar benchmarked positions in Petrocapita's industry peer group in the relevant marketplace. Consideration will also be given to the executive officer's performance based on, among other things, engagement, contribution and competency.

Annual Bonus

Annual bonus cash awards are intended to motivate and reward executive officers for achieving and surpassing annual corporate and individual goals. Bonus awards for executive officers will be reviewed, considered and approved by the Board. Under Petrocapita's annual bonus program, the targeted annual bonus percentage for the executive officers is expected to be competitive with market practice and reviewed by the Board annually. Based on performance, actual annual payouts under the plan are expected to range from zero to two times the targeted bonus value. The Board, in its sole discretion, will have the ability to make additional awards (supplemental bonuses) to executive officers on an annual basis to award exceptional performance.

Long-Term Incentive Plans

To date no options or other securities-based incentive awards have been granted to any of the executive officers or to any directors or Trustees.

Other Benefits

Petrocapita's executive compensation program is expected to include typical industry perquisites. All elements of such perquisites shall be reviewed, considered and recommended by the Board and, with respect to the Chief Executive Officer, Chief Operating Officer and Chief Financial Officer, approved by the Board.

Risks of Compensation Policies and Practices

The Board from time to time considers the implications of the risks associated with Petrocapita's compensation policies and practices and has not identified any material risks from such policies and practices that are reasonably likely to have a material adverse effect on Petrocapita. However, currently a material portion of the executives' compensation is based on short term compensation. In the future, the Board may consider adopting stock based compensation arrangements directly relating to management building long term Unitholder value and thereby further aligning interests of management and Unitholders.

Summary Compensation Table

The following table sets forth information concerning the total compensation paid by Petrocapita during the last three financial years to each of its chief executive officer and chief financial officer as at December 31, 2014.

Name and Principal Position	Year	Salary ($)	Share-based or Option-based awards ($)	Non-equity incentive plan compensation ($)		All other compensation ($)	Total compensation ($)
				Annual incentive plans	Long-term incentive plans		
Evelyn Studer [1]	2014	145,000	–	–	–	2,500	147,500
Vice President, Finance and	2013	132000	–	10,000	–	2,500	144,500
Chief Financial Officer	2012	108,000	–	–	–	2,380	110,380
David Forrest [2]	2014	–	–	–	–	87,000 [3]	87,000
Former President	2013 [4]	–	–	–	–	–	–
	2012 [4]	–	–	–	–	–	–

Notes:

(1) Prior to April 2015, Ms. Studer served as Controller of the Administrator since January 2012. Her compensation as disclosed in this table was paid to her in her capacity as a non-executive officer during the covered period.

(2) Mr. Forrest previously served as President of the Administrator from February 2010 until the appointment of Alex Lemmens as President and Chief Executive Officer effective March 15, 2015.

(3) This amount represents management fees paid to a company controlled by Mr. Forrest.

(4) Mr. Forrest did not receive any compensation from Petrocapita during 2013 or 2012.

No officer or other person received total compensation of more than $150,000 from Petrocapita for the year ended December 31, 2014.

Mr. Lemmens, who currently serves as President and Chief Executive Officer of the Administrator, was appointed to such offices effective March 15, 2015, and was not employed or otherwise engaged by Petrocapita in any capacity prior to that time.

Compensation for Trustees and Directors

Trustees and directors of Petrocapita have not historically been compensated for their service as such. In connection with Messrs. Marr and Van Rootselaar joining Petrocapita as independent Trustees and directors the Board is revisiting its director compensation practices. It is currently anticipated that each non-executive Trustee and director will be paid an annual cash retainer of up to $10,000. Petrocapita will also reimburse Trustees and directors for all reasonable expenses incurred in order to attend meetings, and may from time to time, if determined appropriate, compensate Trustees and directors with additional fees for their service on special projects or special committees of the Board.

The goal of Petrocapita's director compensation program is to attract and retain qualified directors to supervise the management of Petrocapita.

Termination and Change of Control Benefits

Petrocapita has no written contract, agreement, plan or arrangement that provides for payments or benefits to executive officers in connection with any termination, resignation, retirement, change of control of Petrocapita or change in the officer's responsibilities.

Indemnification of Trustees, Directors and Officers

Petrocapita will enter into indemnity agreements with each Trustee, director and officer pursuant to which it will agree to indemnify the Trustee, director or officer, as applicable, from liability arising in connection with the performance of their duties. Any such indemnity agreements will conform to the statutory conditions for and restrictions on indemnification under the ABCA.

INDEBTEDNESS OF TRUSTEES, DIRECTORS AND EXECUTIVE OFFICERS

Except as disclosed below and for "routine indebtedness" (as defined in Form 51-102F5 of the Canadian Securities Administrators), no person who is, or at any time since January 1, 2014 was, a Trustee or a director or executive officer of the Administrator, a proposed nominee for election as a trustee or director, or an associate of any such Trustee, director, executive officer or proposed nominee, is or at any time since January 1, 2014 has been indebted to the Trust or any of its subsidiaries, or to another entity where such debt is or was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Trust or any of its subsidiaries.

INDEBTEDNESS OF TRUSTEES, DIRECTORS AND EXECUTIVE OFFICERS UNDER SECURITIES PURCHASE AND OTHER PROGRAMS

Name and Principal Position	Involvement of Trust or Subsidiary	Largest Amount Outstanding During Year Ended December 31, 2014 ($)	Amount Outstanding as at June 30, 2015 ($)
David Forrest [(1)] Former President	Corporation as lender [(1)(2)]	$37,087.53	$12,972.88

Notes:

(1) Mr. Forrest previously served as President of the Administrator from February 2010 until the appointment of Alex Lemmens as President and Chief Executive Officer effective March 15, 2015. In 2011, Brahma Resources Ltd., a company owned by Mr. Forrest, borrowed $40,000 from Petrocapita and used such funds to exercise a previously-granted option to purchase 833,342 Trust Units.

(2) The loan is represented by a promissory note and bears interest at 6% per annum, accrued daily and compounded and paid annually or as otherwise agreed, and is repayable on demand. During the year ended December 31, 2014, $18,000 (2013 – $7,500) in principal payments were received by Petrocapita.

AUDIT COMMITTEE

Audit Committee Mandate

The Trustees will adopt a written mandate and terms of reference for the Audit Committee, which sets out the Audit Committee's responsibility for, among other things reviewing the Trust's consolidated financial statements and the Trust's public disclosure documents containing financial information and reporting on such review to the Trustees and the Board, as applicable, ensuring Petrocapita's compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of Petrocapita's external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee Mandate anticipated to be adopted by the Trustees is attached as Appendix C.

Composition of the Audit Committee

The Audit Committee is anticipated to be comprised of Messrs. Marr (Chair), Van Rootselaar and Lemmens, each of whom is considered financially literate as determined under NI 52-110. Each of Messrs. Marr and Van Rootselaar is considered independent within the meaning of NI 52-110. As Chief Executive Officer of the Administrator, Mr. Lemmens is not independent for the purposes of NI 52-110. The Audit Committee will be constituted prior to the time of filing a final version of this prospectus.

Neither the Trustees nor the Board of Directors have previously appointed an audit committee.

Although all anticipated members of the Audit Committee are financially literate, and a majority are independent, within the meaning of those terms under NI 52-110, the Trust is an issuer that does not, and as at the end of its most recently completed financial year did not, have any of its securities listed or quoted on any of the Toronto Stock Exchange, a U.S. marketplace or a marketplace outside of Canada and the United States of American, and is therefore a "venture issuer" within the meaning of NI 52-110 that, as such, is exempt from the audit committee composition requirements (including with respect to independence and financial literacy) set forth in Part 3 of NI 52-110.

Relevant Education and Experience

Petrocapita believes that each proposed member of the Audit Committee possesses: (a) an understanding of the accounting principles used by Petrocapita to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and provisions; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Petrocapita's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

For a summary of the relevant education and experience of each proposed member of the Audit Committee, see "*Trustees, Directors and Executive Officers – Biographies*".

Pre-approval Policies and Procedures

The Audit Committee will adopt specific policies and procedures for the engagement of non-audit services, as described in the Audit Committee Mandate. See Appendix C.

External Auditor Service Fees

The following table summarizes the fees paid by Petrocapita to Collins Barrow Calgary LLP, its external auditors, for audit and other services during the period indicated.

Category of Fees	Year Ended December 31, 2014 ($)	Year Ended December 31, 2013 ($)
Audit Fees [(1)]	45,000	45,000
Audit-Related Fees [(2)]	nil	nil
Tax Fees [(3)]	4,000	nil
All Other Fees [(4)]	nil	nil
Total	49,000	45,000

Notes:

(1) "Audit Fees" means the aggregate fees billed by Petrocapita's external auditors in each of the last two years for audit fees, and consist of fees for services provided in connection with the audit of the Trust's annual consolidated financial statements

(1) "Audit-Related Fees" means the aggregate fees billed in each of the last two fiscal years for assurance and related services by the Trust's external auditors that are reasonably related to the performance of the audit or review of the Trust's financial statements and are not reported under "Audit Fees" above.

(2) "Tax Fees" means the aggregate fees billed in each of the last two years for professional services rendered by the Trust's external auditors for tax compliance, tax advice and tax planning.

(3) "All Other Fees" means the aggregate fees billed in each of the last two fiscal years for products and service provided by the external auditor, other than Audit Fees, Audit-Related Fees and Tax Fees.

CORPORATE GOVERNANCE

Board and Trustees

As at the date hereof, the Board is comprised of four individuals: Alex Lemmens, Greg Marr, Ben Van Rootselaar and Richard Mellis. Each of these individuals is also a Trustee of the Trust. See "*Administration Agreement*" and "*Trustees, Directors and Executive Officers*".

Pursuant to National Instrument 58-101 – *Disclosure of Corporate Governance Practices* of the Canadian Securities Administrators ("**NI 58-101**"), a director or trustee is considered to be "independent" of Petrocapita if he has no direct or indirect "material relationship" with Petrocapita, being a relationship that could, in the view of the Board or Trustees, as applicable, be reasonably expected to interfere with the exercise of the director's or trustee's independent judgment. NI 58-101 deems certain current and historical relationships to constitute a material relationship for these purposes.

Greg Marr and Ben Van Rootselaar are each considered to be independent of Petrocapita within the meaning of NI 58-101 and have no relationship with Petrocapita beyond service as a director and Trustee. Alex Lemmens and Richard Mellis are not considered to be independent as each currently serves as an executive officer of the Administrator – Mr. Lemmens as President and Chief Executive Officer and Mr. Mellis as Vice President, Land and Environment.

Orientation and Continuing Education

Petrocapita does not currently have a formal orientation and educational program for new directors or Trustees, but does provide such orientation and education on an informal basis. The directors and the Trustees believe that this is a practical and effective approach in light of their particular circumstances, including the limited number of directors and trustees and their experience and expertise.

No formal continuing education program currently exists for the directors or Trustees; however, directors and Trustees are encouraged to attend, enroll in or participate in courses and/or seminars dealing with financial literacy, corporate governance and related matters. Each director and Trustee has the responsibility for ensuring that he maintains the skill and knowledge necessary to meet his obligations as a director and trustee, as applicable.

Ethical Business Conduct

The directors and Trustees encourage and promote a culture of ethical business conduct through communication and supervision as part of their overall responsibility for stewardship of Petrocapita and its business and affairs. Communication and supervision is facilitated by the fact that Petrocapita is a relatively small organization.

In considering any transactions or agreements in respect of which a director, trustee or executive officer has or may have a material interest, the Board or Trustees, as applicable, will require that the interested party declare their interest and abstain from voting on any decision of the Board or the Trustees, as applicable, to approve or disapprove of the transaction or agreement. In all circumstances, each director and Trustee is required to act honestly and in good faith with a view to the best interests of Petrocapita.

Nomination of Directors and Trustee

Given the relatively small size of Petrocapita and its early stage of development, neither the Board nor the Trustees have appointed a nomination committee or put in place formal procedure for the identification of potential directors or trustees, as applicable. The functions of such a committee can be served by the Board and the Trustees, as applicable.

Compensation

The Board, as a whole, determines the compensation of the directors and executive officers of the Corporation. In setting compensation, the Board is guided by the nature of Petrocapita's business, Petrocapita's size and stage of development, current industry practices and the resources available to provide compensation. The Board may from time to time seek out the compensation policies of other comparable entities to ensure that Petrocapita is able to attract and retain its directors and executive officers. The Trustees, as a group, determine the compensation of the Trustees by also taking into account the factors set forth above. See "*Executive Compensation*".

Other Board Committees

Petrocapita has no standing committees of directors or Trustees and does not currently intend to constitute any such committee other than the Audit Committee.

Board/Trustee Assessments

Petrocapita has not commenced a formal process of assessing the Board, the Trustees, as a group, the Audit Committee or individual directors or Trustees.

OPERATIONAL MATTERS

Transportation

Access to the market is currently a concern for the Canadian oil and gas industry as a whole. Any producer's ability to market its product largely depends upon its ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets or to arrange for alternate transportation such as rail. While several pipeline expansions and proposed projects have been commenced, announced or are waiting for regulatory approval, the lack of firm pipeline capacity and regulatory delays for the approval of certain projects continues to affect the oil and gas industry and limit a producer's ability to market their oil and natural gas production. While the use of rail transportation has significantly increased over the last few years, similar to the concern over the lack of pipeline capacity, issues with respect to capacity and uncertainty with respect to anticipated (but unknown) regulatory changes may also impact a producer's ability to access the market through this alternative method.

Petrocapita's oil is transferred from the producing fields by truck, rail and pipeline.

Competition

The oil and gas industry is intensely competitive, and Petrocapita competes with other companies that, in many cases, have greater resources than Petrocapita. Many of these companies not only explore for and produce oil and natural gas, but also have midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than Petrocapita's financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Petrocapita's larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, provincial and local laws and regulations more easily than Petrocapita, which would adversely affect its competitive position.

Petrocapita's ability to acquire additional properties and to discover reserves in the future will be dependent upon its ability to evaluate and select suitable properties and to complete transactions in a highly competitive environment. In addition, because Petrocapita has fewer financial and human resources than many companies in its industry, Petrocapita may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Furthermore, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas. See "*Risk Factors*".

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. As a result, construction, production and trucking activity are typically lower in Petrocapita's second fiscal quarter than in other fiscal quarters. Other seasonal factors and unexpected weather patterns also affect exploration and production activity and cause fluctuations in the demand for Petrocapita's goods and services, with demand for natural gas rising during cold winter months and hot summer months. See "*Risk Factors*".

Business Cycle and Seasonality in the Oil and Gas Industry

Crude oil prices fluctuate with the balance between world supply and demand, levels of inventory, changes in policy of the Organization of the Petroleum Exporting Countries ("**OPEC**") and geopolitical events. Natural gas prices are influenced by North American levels of inventory and storage, estimates of current and forecast supply and weather expectations. See "*Risk Factors*" for a more detailed discussion of factors which may affect Petrocapita's business.

The development of crude oil and natural gas reserves is dependent on access to development areas. Seasonal weather variations, including winter freeze-up and spring break-up, affect access to various properties under certain circumstances. See "*Risk Factors*" for a more detailed discussion of factors which may affect Petrocapita's business.

Trends in the Oil and Gas Industry

Management has observed certain business and economic factors which may influence Petrocapita's business in the short term.

Oil prices, while at relatively low levels compared with historical averages, are volatile, making it difficult to budget for acquisitions and development. Another factor that influences realized oil prices are foreign exchange rates, as oil

and natural gas production in Canada is ultimately priced in U.S. dollars. The efforts of Petrocapita to acquire, sustain and increase production, along with robust commodity prices are faced by a very competitive market for equipment, skilled labour and the acquisition of oil and gas properties and related assets. See "*Risk Factors*" for a more detailed discussion of factors which may affect Petrocapita's business.

Exploration Risks

Exploration drilling involves substantial risk and no assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. While Petrocapita is of the view that its personnel have the skills and that it will have the resources to achieve its objectives, participation in the exploration for and the development of crude oil and natural gas has a number of inherent risks. See "*Risk Factors*" for a discussion of exploration risk.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- political conditions, including the risk of hostilities and political unrest in the Middle East and other regions throughout the world;
- increases or decreases in crude oil quality and market differentials;
- the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by Petrocapita for its crude oil and natural gas;
- North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- global and domestic economic and weather conditions;
- the impact of tax and incentive regimes to credit risk;
- the price and availability of alternative fuels; and
- the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of management's control. To mitigate a portion of these risks, Petrocapita actively engages in price risk management activities.

Substantial Capital Requirements

Petrocapita anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Petrocapita's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated from operations, will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Petrocapita. Moreover, future activities may require Petrocapita to alter its capitalization significantly. Transactions involving the issuance of securities may be dilutive. The inability of Petrocapita to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects. See "*Risk Factors*" for further discussion of capital requirements.

INDUSTRY CONDITIONS

Government Regulation

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and Petrocapita's oil and gas operations are subject to various Canadian federal, provincial and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage,

transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning Petrocapita's operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of Petrocapita's operations. Petrocapita cannot predict the ultimate cost of compliance with these requirements or their effect on its operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of crude oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity.

Although Petrocapita does not expect that these controls and regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Petrocapita is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Export and Pricing

Oil

Producers of crude oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on crude oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms and the world price of oil. Oil may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the National Energy Board (the "**NEB**"). Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m3/day) require authorization by the board of the NEB. The Governor in Council must approve the exportation of any gas prior to the issuance of a license for the same.

The Alberta and Saskatchewan governments also regulate the volume of natural gas that may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market considerations.

Pipeline Capacity and use of Rail

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity in Canada has been constrained. The space deficit is unlikely to be resolved quickly given that heavy oil production is set to increase, while the prospects for major increases in pipeline capacity in the near future are uncertain. In terms of increasing overall pipeline capacity, several projects are currently underway and some have been recently completed, including Enbridge Inc.'s Line 5 expansion project, completed in mid-2013, brought an additional 50,000 barrels/day of light oil into Sarnia, Ontario. Enbridge has also added 985,000 barrels/day of transport capacity between Western Canadian heavy oil and U.S. refineries in Gulf of Mexico through the twinning of the Seaway pipeline and completion of the Flanagan South pipeline. Enbridge's proposal to reverse and expand its Line 9 pipeline from North Westover, Ontario, to Montreal, Quebec, could deliver approximately 300,000 barrels of oil per day to Quebec refineries. The NEB approved the Line 9 project, subject to 30 conditions, on March 6, 2014. Finally, the federal government recently accepted the NEB's approval of the Northern Gateway Pipeline. However, before construction can begin, Enbridge is required to apply for permits from federal and provincial governments as well as demonstrate that the project will meet the NEB's 209 conditions. The pipeline would carry up to 525,000 barrels of oil per day from Alberta to marine terminals in Kitimat, BC for export.

Current oil sands production is approximately 2.3 million barrels per day and the production rate is expected to more than double to 4.8 million barrels per day by 2030 (CAPP Crude Oil Forecast Markets and Transportation June 2014). Accordingly, finding additional export capacity to deal with the increase in Canada's crude oil production is a primary concern. There are several pipeline proposals in the works that could help to alleviate access problems from Western Canada's Sedimentary Basin to the international markets: the Keystone XL Pipeline, TransCanada's Energy East Pipeline and Kinder Morgan's Trans Mountain Express Pipeline. While the use of rail transportation has significantly increased over the last few years, similar to the concern over the lack of pipeline capacity, issues with respect to capacity and uncertainty with respect to anticipated (but unknown) regulatory changes may also impact a producer's ability to access the market through this alternative method.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the Canadian, United States and Mexican governments came into effect on January 1, 1994. Under NAFTA, the Canadian government is free to determine whether exports of energy resources to the United States or Mexico should be allowed, provided that export restrictions do not: (1) reduce the proportion of energy resources exported relative to energy resources consumed domestically (with the most recent 36 month period proportion used as the basis for comparison); (2) impose a higher export price than domestic price (subject to an exception relating to certain voluntary measures that restrict the volume of exports); and (3) disrupt normal channels of supply.

NAFTA prohibits discriminatory border restrictions and export taxes and also prohibits the imposition of minimum or maximum export or import price requirements except with respect to the enforcement of countervailing and anti-dumping orders and undertakings. Discipline on regulators is addressed as the signatories to NAFTA agree to ensure that their regulatory bodies provide equitable implementation of regulatory measures and minimize the disruption of contractual arrangements.

Royalties and Incentives

Overview

For crude oil, natural gas and related production from Federal or provincial government lands, the royalty regime is a significant factor in the profitability of Petrocapita's production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the resource owners, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest

through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Conventional oil royalties in Alberta are set according to a sliding rate formula with separate elements accounting for oil price and well production. Similarly, natural gas royalties are set according to a sliding rate formula which is sensitive to price and production volume. In 2009, the Alberta government implemented the Alberta Royalty Framework (the "**ARF**") which introduced a new well event-based royalty rate formula with a quantity component that is influenced by a reported well production. The ARF also announced a five-year program of "transitional" royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. This program gave conventional oil and natural gas licensee's the option to select a transitional royalty rate instead of the conventional rate, provided that certain criteria were met. The option was only available where well events occurred on wells with spud dates between November 19, 2008 and January 1, 2011 and where the measured well depth was between 1,000 and 3,500 meters. The option also had to be exercised on the earlier of the last day of the first production month of the well event, or December 31, 2010. Any such wells paying transitional royalty rates automatically shifted to the conventional rate on January 1, 2014.

Under the ARF, royalty rates for conventional oil currently range from 0% to 40% and royalty rates for natural gas (methane and ethane) currently range from 5% to 36%. ARF rates for propane and butane are fixed at 30% and the rate for pentane is fixed at 40%. Condensate royalties under the ARF are calculated in a similar manner to royalties for conventional oil and currently range from 0% to 40%.

The Alberta government has also introduced a number of royalty reduction and incentive programs to encourage oil and gas exploration and development in Alberta, which include the following programs, among others, currently in effect:

- The Deep Oil Exploration Program (the "**DOEP**") and the Natural Gas Deep Drilling Program (the "**NGDDP**") are two programs that became effective on January 1, 2009. These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells that: (a) are spud or deepened on or after May 1, 2010, (b) are natural gas wells with a gas-oil ratio of greater than 1800:1, (c) have a Crown interest greater than zero, and (d) have their producing interval at a true vertical depth greater than 2,000 metres. In the case of exploratory wells, the NGDDP has an escalating royalty credit in line with progressively deeper wells from $625 per metre to a maximum of $3,750 per metre and there are additional benefits for the deepest wells. In the case of development wells, the escalating royalty credit ranges from $625 per metre to a maximum of $3,000 per metre. The NGDDP was originally announced as five year programs and any wells spudded after December 31, 2013, or any wells selecting the transition option are not able to qualify. All royalty adjustments under the program terminate with five years of the finished drill date of the well or December 31, 2018, whichever occurs first. The regulation which established the program will expire on November 30, 2016.

- The New Well Royalty Rate ("**NWRR**") program provides a maximum 5% royalty rate for the first 12 months of production. The incentive program applies to new wells that began producing oil or natural gas prior to April 1, 2009 or to wells that have recommenced production during certain periods, had no production during certain prior periods. In addition, the well must have a fluid core of oil, gas or non-project oil sands, be subject to royalty payments and have a Crown interest greater than zero. The incentive program applies to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. As of March 11, 2010, the Alberta government made the NWRR a permanent feature of the royalty system.

- Enhanced oil recovery ("**EOR**") methods that use the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, chemicals or other approved substances allow for the recovery of additional oil. To promote this additional recovery, the Crown has introduced the Enhanced Oil Recovery Program ("**EORP**") and to optimize petroleum resources using EOR methods, the Alberta Government has issued guidelines, effective January 1, 2014. These guidelines explain the administration of the EORP under the new Enhanced Oil Recovery Royalty Regulation (AR156/2014), also effective January 1st, 2014, and assists operators in completing the application process.

- Horizontal gas wells with a Crown interest greater than zero will receive a maximum royalty of 5% for 18 producing months or 500 million cubic feet of gas of production (whichever is reached first). This applies retroactively to wells where drilling commenced on or after May 1, 2010.

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production monthly limits set according to the depth of the well. This applies retroactively to wells that commenced drilling on or after May 1, 2010. The Horizontal Oil New Well Royalty Rate program extends the maximum 5% New Well Royalty Rate ("**NWRR**") on qualifying horizontal oil wells and horizontal non-project oil sands wells from 12 producing months to between 18 and 48 producing months, up to a maximum volume of between 50,000 and 100,000 boe of production, monthly production and volume limits set according to the depth of the well. This program applies to qualifying wells spud on or after May 1, 2010.

In conjunction with the release of the new royalty curves for the ARF, the Alberta government also announced its Emerging Resources and Technology Initiative ("**ERTI**") intended to accelerate new technologies and encourage the development of unconventional resources. The ERTI continues to be reviewed. The Alberta government would provide the industry with three years notice where any major changes in the program would be required or if it intends to discontinue the program.

In June 2015, the Alberta government announced a review of Alberta's Crown royalty framework. A review panel has been appointed with a stated mandate to identify ways to optimize returns to Albertans as owners of the resource, industry investment, diversification opportunities and responsible development. The panel is expected to conclude its work by the end of 2015, and the government has indicated that the panel's advice will be considered prior to any decisions on changes to the current royalty structure. In the meantime, the Alberta government has committed that the current royalty framework will remain in place until the end of 2016.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and natural gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act* (Saskatchewan). For resource corporations, the Resource Surcharge rate is 3.0% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations. A Resource Surcharge rate of 1.7% is applicable to all oil and natural gas related sales that Petrocapita generates.

The amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as heavy crude oil, southwest designated oil, or non-heavy crude oil other than southwest designated oil. The conventional royalty and production tax classifications (fourth tier oil, third tier oil, new oil and old oil) depend on the finished drilling date of a well and are applied to each of the 3 crude oil types slightly differently. Heavy crude oil is classified as third tier oil produced from a vertical well (having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier

oil produced from a well (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002, and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy crude oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, or conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" applicable to that classification of oil. Currently the "Production Tax Factor" is 6.9 for "old oil", 10 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero. The majority of Petrocapita's production is classified as "fourth tier oil".

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per cubic metre for third and fourth tier oil and $50 per cubic metre for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy crude oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy crude oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy crude oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy crude oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Natural gas may be classified as non-associated natural gas or associated gas and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated natural gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

In December 2010, Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act*, 2010 (Saskatchewan) which replaced the existing *Freehold Oil and Gas Production Tax Act* (Saskatchewan) and is intended to facilitate more efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* (Saskatchewan) which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 (Saskatchewan) which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35/GJ for third and fourth tier gas and $0.94/GJ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above

base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

The Saskatchewan government currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 cubic metres for deep development vertical oil wells, 4,000 cubic metres for non-deep exploratory vertical oil wells and 16,000 cubic metres for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 cubic metres for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 cubic metres (approximately 37,740 bbls) for non-deep horizontal oil wells and 16,000 cubic metres (approximately 100,640 bbls) for deep horizontal oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate; Petrocapita's Viking oil wells are considered non-deep horizontal oil wells under this incentive and are subject to a Crown royalty rate equal to the lesser of (a) the "fourth tier oil" Crown royalty rate and (b) 2.5% and a freehold production tax rate of 0% until 6,000 cubic metres (approximately 37,740 bbls) of oil have been produced;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime Applicable to Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing Prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- *Royalty/Tax Regime Applicable to Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing On or After April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% percent on operating income from enhanced oil recovery projects pre-payout and 8% post-payout;

- *Royalty/Tax Program for High Water-Cut Oil* Wells treating incremental oil resulting from qualified investments on eligible high water-cut oil wells as third tier oil for the purposes of royalty calculation; and

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells Drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 cubic metres, by classifying horizontal gas wells as exploratory gas wells for the purposes of royalty calculation. After the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate.

In 1975, the Saskatchewan government introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to 7 years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 10 different licensing fees, which resulted in an aggregate of

20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Saskatchewan government to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Land Tenure

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective provincial and Federal governments. Tenure is the process of leasing and administering petroleum and natural gas rights owned by the Crown.

Petroleum and natural gas rights owned by the province can be obtained via competitive bid auctions which are held approximately every two weeks. Companies that obtain licenses or leases to explore and develop Crown resources are subject to the relevant regulatory requirements.

Lands in a petroleum and natural gas license are earned by the drilling of a well. A lease is proven productive at the end of its five-year term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease. The tenure only comes to an end when the holder can no longer prove his agreement is capable of producing oil or gas. Jurisdictions in western Canada have legislation in place for mineral rights reversion to the Crown where formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Production and Operation Regulation

The oil and gas industry in Alberta and Saskatchewan is highly regulated and subject to significant control by a provincial regulator. Petrocapita must obtain regulatory approval for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable provincial regulator, Petrocapita must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach thereof may result in fines or other sanctions.

Environmental Regulation

As an operator of oil properties in Canada, Petrocapita is subject to stringent federal, provincial and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

Environmental legislation in the province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta). The *Oil and Gas Conservation Act* (Alberta) establishes a regulatory regime and scheme of approvals for the development of oil and gas resources and related facilities in Alberta.

The Alberta Environmental Monitoring, Evaluation and Reporting Agency ("**AEMERA**") was established under the *Protecting Alberta's Environment Act* in 2014, and aims to become the comprehensive source of data and information on the state of the environment in Alberta. AEMERA is responsible for monitoring the air and water quality in the province, ambient monitoring of biodiversity, involvement in the Joint Oil Sands Monitoring ("**JOSM**") project, and working with federal stakeholders and the federal government in the oil sands region to coordinate and enhance monitoring activities in the area. By 2017, AEMERA aims to create and launch an information-sharing platform to provide open access to data on key ambient air, water, land and biodiversity indicators and related environmental information.

Environmental compliance in Saskatchewan is governed in general by the *The Environmental Management and Protection Act* (Saskatchewan) and *The Oil and Gas Conservation Act* (Saskatchewan). Further federal environmental legislation is embodied in the *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012*.

In Saskatchewan, on April 1, 2012, a bill enacting changes to *The Oil and Gas Conservation Act* (Saskatchewan) was proclaimed into force in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* (Saskatchewan) (the "**OGC Regulations**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The expressed aim of the amendments to the *The Oil and Gas Conservation Act* (Saskatchewan) and associated regulations was to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGC Regulations, Saskatchewan implemented a number of operational aspects, including the increased demand for record- keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Petrocapita currently operates or leases, and have in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although Petrocapita utilizes and have utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under Petrocapita's control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several or strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed of wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

Petrocapita believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions. The province of Alberta has recently announced its intention to adopt mandatory disclosure requirements and an online registry for hydraulic fracturing activities and ingredients. Additionally, the Alberta Energy Regulator released a new Hydraulic Fracturing Directive, effective August 21, 2013, which sets out its requirements for managing the subsurface integrity of wells associated with hydraulic fracturing. While Petrocapita believes that it is in substantial compliance with applicable environmental laws and regulations presently in effect and that continued compliance with existing requirements will not have a material adverse impact on us, it cannot give any assurance that it will not be adversely affected in the future.

Climate Change Regulation

Federal

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other greenhouse gases ("**GHG**"). The first commitment period under the Kyoto Protocol was the five-year period from 2008-2012. In December 2011, the Canadian federal government announced that it would not agree to a second commitment period under the Kyoto

Protocol after 2012. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain. The federal government instead endorsed the Durban Platform, a broad agreement reached among the 194 countries that are party to the United Nations Framework Convention on Climate Change, during a conference held in Durban, South Africa in December 2011. The Durban Platform sets forth a process for negotiating a new climate change treaty that would create binding commitments for all major GHG emitters. The Canadian government has expressed cautious optimism that agreement on a new treaty could be reached by 2015. The Durban Platform followed the Copenhagen Accord reached in December 2009 as government representatives met in Copenhagen, Denmark to negotiate a successor to the Kyoto Protocol. The Copenhagen Accord represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a binding international treaty. Although Canada had committed under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, the target is not legally binding.

Domestically, the Canadian federal government released in 2007 its *Regulatory Framework for Air Emissions*, which was updated in March 2008 in a document entitled *Turning the Corner: Taking Action to Fight Climate Change*. Canada's previous GHG emission reduction target was 20% from 2006 levels by 2020, but on January 30, 2010 the Canadian federal government announced a new GHG emission reduction target consistent with its commitment under the Copenhagen Accord to reduce GHG emissions to 17% below 2005 levels by 2020. The federal government also plans to further reduce GHG emissions by 30% below 2005 levels by 2030. Canada has formally submitted this target, referred to as an intended Nationally Determined Contribution, to the United Nations Framework Convention on Climate Change, in connection with negotiations of a new international climate treaty at the Paris Climate Conference scheduled for December 2015. In December 2014 the Canadian government published "Canada's Action of Climate Change" declaring its intention to take action on climate change by reducing GHG emissions by implementing a sector-by-sector regulatory approach to protect the environment and support economic prosperity. To date, regulations for Canada's renewable fuels transportation and coal-fired electricity sectors have been developed. However, none have been developed for the oil and gas sector and regulations for the electricity sector aren't expected to take effect until 2015.

In 2009, the Canadian federal government had previously announced its commitment to work with the provincial governments to implement a North America-wide cap-and-trade system for GHG emissions, in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems.

Alberta

The *Climate Change and Emissions Management Act* (Alberta) provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations include the Specified Gas Emitters Regulation (the "**SGER**"), which imposes GHG emissions limits, and the Specified Gas Reporting Regulation (the "**SGRR**"), which imposes GHG emissions reporting requirements.

The SGER, first made effective July 1, 2007 and recently renewed by the Alberta government for two years to June 2017, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (i.e., the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and the baseline for a new facility reflects emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions intensity is currently 12% from its baseline, however on June 25, 2015 the SGER was amended such that the stringency level

will increase to 15% in 2016 and to 20% in 2017. For a new facility, the required reduction from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the reduced stringency level (currently 12% from baseline, and set to increase to 15% in 2016 and 20% in 2017) is reached. Once reached, the reduced emissions intensity level must thereafter be maintained over time.

There are four ways for operators of facilities that are subject to the SGER to comply with the GHG emissions intensity reduction requirements: (i) improve emissions intensity at the facility by physically abating GHG emissions; (ii) purchase emission performance credits (created in respect of facilities to the extent they are able to surpass emissions reductions requirements under the SGER); (iii) purchase emission offset credits in the open market, which are generated from Alberta-based offset projects; and/or (iv) purchase "fund credits" by contributing to the Alberta Climate Change and Emissions Management Fund (the "**Fund**") run by the Alberta government. Contribution costs to the Fund have historically been $15 per tonne of GHG, and are set to remain at that level for 2015. On June 25, 2015, the Alberta government announced that contribution costs will increase to $20 per tonne in 2016 and then to $30 per tonne in 2017. Compliance reports for facilities subject to the SGER are due to Alberta Environment and Parks on March 31 annually.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emission levels at or equal to the amount set by the *Specified Gas Reporting Standard*, a document which was incorporated by reference into the SGRR and was published by Alberta Environment and Parks. As of March, 2014, the threshold level for submission of a specified gas report is the release of 50,000 tonnes of GHGs in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations.

In January 2008, the Alberta government had announced a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050. On June 25, 2015, the Alberta government announced the commencement of a consultation process with public, industry, environmental groups and First Nations on climate change strategies in the province. The report resulting from such consultation, currently expected to be released by December 2015, will be considered by the government in its development of a new provincial climate change strategy, and is expected to lead to further modifications to the existing regulatory framework under the *Climate Change and Emissions Management Act* (Alberta).

Saskatchewan

On June 22, 2011, the Saskatchewan government released the Upstream Petroleum Industry Associated Gas Conservation Standards, which aim to reduce emissions resulting from the flaring and venting of associated gas. These standards were jointly developed with industry, and their implementation commenced on July 1, 2012 for new wells and facilities. The standards apply to all existing licensed wells and facilities as of July 1, 2015.

The Management and Reduction of Greenhouse Gases Act (Saskatchewan) received Royal Assent in the Province of Saskatchewan on May 20, 2010 but still awaits proclamation. The new legislation would establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation. A draft of the proposed regulations to accompany the Act would require emissions to be reduced to 20% below 2006 levels by 2020. The Act was amended April 2013 to include a citizen's right to request an investigation for an infraction under the act as per the requirement under *Canadian Environment Protection Act* in order to obtain an equivalency agreement with the federal government. No regulations have been passed at this point. The Saskatchewan government announced in November 2014 the adoption of a new environmental code introducing a new results-based system although regulation of GHG emissions is not included in this first edition of the code.

Implications of Climate Change Regulations

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect Petrocapita's business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce Petrocapita's emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects.

Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect Petrocapita's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by Petrocapita. The imposition of such measures might negatively affect Petrocapita's costs and prices and have an adverse effect on earnings and results of operations.

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

Petrocapita believes that it is in material compliance with applicable environmental legislation and is committed to continued compliance. Petrocapita believes that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue, and anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

RISK FACTORS

An investment in Trust Units involves a substantial degree of risk and is highly speculative due to the nature of the Trust's business and the risks inherent in the oil and gas industry in which Petrocapita operates. As a result, investors should only consider investing in Trust Units if they can afford to lose their entire investment. Investors should carefully consider the risks described below and the other information contained in this prospectus before making an investment decision. The occurrence of any of the following risks could materially and adversely affect the business, financial condition, results of operations, cash flows and future prospects of Petrocapita. A material adverse change could cause a decline in the value or price of Trust Units and investors could lose all or part of their investment in the Trust Units. The risks and uncertainties described below are not the only ones Petrocapita is facing. There are additional risks that Petrocapita does not currently know about or that it currently considers immaterial, which may also impair Petrocapita's business operations and cause the value or price of the Trust Units to decline. There can be no assurance that the risk management steps taken by Petrocapita will successfully mitigate the risks described below, or other unforeseen risks, or prevent any resulting loss.

Risks Related to Petrocapita's Production, Development and Exploration Operations

Oil and natural gas prices are volatile. A substantial or extended decline in energy commodity prices may adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects and Petrocapita's ability to meet its capital expenditure obligations and financial commitments.

Petrocapita's results of operations, financial condition and the value of its reserves depend, in part, on the marketability and price of crude oil and natural gas, as applicable. Oil and gas prices are determined by a wide range of political and economic factors external to Petrocapita and beyond its control. These factors include economic conditions in the U.S., Canada and worldwide, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, weather conditions, including weather-related disruptions to the North American natural gas supply, the foreign supply of crude oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in oil and gas prices would have an adverse effect on Petrocapita's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects. Lower commodity prices may render Petrocapita's development plans uneconomic.

Petroleum prices are expected to remain volatile in the near future as a result of market uncertainties regarding the supply and demand of these commodities that are caused by the current state of world economies, OPEC actions, increasing North American supplies, sanctions imposed on certain oil producing nations by other countries, ongoing

credit and liquidity concerns and Middle East political concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisition and development and exploitation projects.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. Petrocapita cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on its business, financial condition, results of operations, cash flows and future prospects.

Petrocapita's operating cash flow will be directly affected by the applicable royalty regime.

Alberta and Saskatchewan receive royalties on the production of natural resources from lands in which it owns the mineral rights that are linked to price and production levels and that apply to both new and existing oil and natural gas projects. For further details, see "*Industry Conditions – Royalties and Incentives*" above. There can be no assurance that the provincial governments of Alberta or Saskatchewan or the federal government of Canada will not adopt new royalty regimes that may render Petrocapita's projects uneconomic or that will otherwise adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects. An increase in royalties would reduce Petrocapita's earnings and could make future capital investments or Petrocapita's operations uneconomic. It could also become more difficult to service and repay Petrocapita's debt. Any material increase in royalties would also significantly reduce the value of Petrocapita's assets.

Petrocapita is subject to significant and complex local, provincial, federal and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting its operations or expose Petrocapita to significant liabilities.

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Petrocapita's operations may require licences, approvals, permits and other authorizations from various governmental authorities. Obtaining authorizations and complying with regulations and controls can be costly and cause delays in development and operations. The cost and timing of obtaining such authorizations and complying with regulations, including environmental regulations, could make certain projects, or parts of those projects, uneconomic and could delay development plans and operational timelines established by Petrocapita.

There can be no assurance that Petrocapita will be able to obtain all authorizations that are required to carry out exploration and development of its projects. Any delays or failures to obtain required governmental authorizations could have a material adverse effect on the business, financial condition, results of operations, cash flows and future prospects of Petrocapita.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, Petrocapita's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada). For further discussion of regulations governing the oil and gas industry in the areas in which Petrocapita operates, see "*Industry Conditions*" above.

There can be no assurance that legislation that directly or indirectly regulates or affects the oil and gas industry will not be changed in a manner that will adversely affect Petrocapita. Such changes could occur locally, provincially, nationally or internationally in a wide variety of fields, including areas as diverse as derivatives trading, rail transportation, environmental and tax regulation.

Changes in the ratio of Petrocapita's deemed assets to deemed liabilities or changes to the requirements of any liability management program that Petrocapita must comply with may result in significant increases to the security deposit that Petrocapita must post.

Alberta and Saskatchewan have developed a licensee liability rating program (the "**LLR Program**"), which is designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes unable to pay such costs. This program involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Although Petrocapita is not presently required to post security under either Alberta or Saskatchewan's LLR Program, changes in the ratio of Petrocapita's deemed assets to deemed liabilities or changes to the requirements of the liability management program may result in significant increases to the security that must be posted. There can be no assurance that the Trust will have access to necessary funds in the event that an increased security deposit is required to be posted. See "*Industry Conditions*".

Petrocapita's abandonment and reclamation costs depend on future regulatory requirements.

Petrocapita will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of Petrocapita's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while Petrocapita accrues a reserve in its financial statements for such costs in accordance with IFRS, no assurance can be given that such accruals will be sufficient.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, Petrocapita may determine it prudent, or be required by applicable laws, regulations or regulatory approvals, to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If Petrocapita establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Capital expenditure requirements for replacing or maintaining capital assets are substantial, and will reduce and may exhaust funds otherwise available for potential distribution to Unitholders.

Like other oil and gas producers, Petrocapita faces substantial capital expenditures to maintain and replace capital assets, which must be funded either from cash flows, proceeds from asset sales or new equity or debt capital. Insofar as capital expenditures are funded from cash flows, the amount of funds available for distribution to Unitholders is necessarily reduced, and that reduction may adversely affect the market value of Trust Units. Funding of capital expenditures through increased borrowings will also reduce cash available for distribution as a result of increased debt service costs and repayment requirements, and the dilutive effect of new unit issuances will reduce distributable cash on a per unit basis to the extent capital expenditures are funded through new equity capital. Distributable cash may be eliminated entirely during times of substantial capital or other expenditures (including acquisitions).

Petrocapita's current operating budget contemplates capital expenditures to maintain, replace, improve the marketability of and extend the useful life of its assets of approximately $2.2 million in 2015, of which approximately $700,000 was expended in the six months ended June 30, 2015. Similar annual capital expenditure levels are expected in order to sustain current production levels at projected prices. Based on current and projected operating costs and commodity prices Petrocapita anticipates being able to fund such expenditures through cash flow from operations, but improvements in the price obtained for its product will be necessary for material business expansion or cash distributions.

The exploration, development and production of oil and natural gas are high-risk activities with many uncertainties that could adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Petrocapita depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Petrocapita's aggregate reserves and the production therefrom will decline over time as such existing reserves are exploited. Future increases in Petrocapita's reserves will depend not only on its ability to explore and develop its properties, but also on its ability to select and acquire suitable producing properties or prospects. Petrocapita may not be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. Further commercial quantities of oil and natural gas may not be discovered or acquired by Petrocapita.

Future oil and natural gas exploration and development may involve unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from completed wells. These conditions include delays in obtaining governmental approvals or consents, shut-in of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions will eventually occur and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells drilled may not become productive and Petrocapita may not recover all or any portion of its investment in wells drilled. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. If operating costs increase or Petrocapita does not achieve its expected revenues, Petrocapita's earnings and cash flow will be reduced and its business, financial condition, results of operations, cash flows and future prospects may be materially adversely affected.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage or injury to oil and natural gas wells, production facilities, other property, the environment and people.

Petrocapita may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to Petrocapita.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Petrocapita's operations involve using some of the latest available vertical, slant, deviated, or horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Petrocapita's operations involve utilizing some of the latest drilling and completion techniques as developed by Petrocapita and its service providers. Risks that Petrocapita faces while drilling include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- loss of circulation in or at the base of the Mannville horizon;
- communication with other wellbores adjacent to the drilling wellbore;
- adequate cementing and sealing of zones above or below the prospective zone;

- staying in the desired drilling zone while drilling horizontally through the formation;
- running the casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that Petrocapita faces while completing its wells include, but are not limited to, the following:

- adequate penetration of casing and cement by perforation at the prospective horizon;
- salt water flows from zones outside of the prospective zone;
- sand production from prospective zone;
- sufficient heavy oil flow to lift sand;
- bottom hole pump failure;
- ability to stimulate the zones of interest;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion.

If Petrocapita's drilling results are less than anticipated, the return on its investment for a particular project may not be as attractive as it anticipated, and it could incur material write-downs of unevaluated properties. Additionally, the value of Petrocapita's undeveloped acreage could decline in the future.

The substantial majority of Petrocapita's total reserves are non-producing and/or undeveloped, and may not ultimately be developed or produced.

The substantial majority of Petrocapita's total reserves are non-producing and/or undeveloped. These reserves may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. Furthermore, not all of Petrocapita's undeveloped or developed non-producing reserves may be ultimately produced at the time periods Petrocapita has planned, at the costs it budgeted or at all.

Petrocapita's identified drilling locations are scheduled out over three years in the Reserves Report years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Petrocapita's proved and probable undeveloped reserves are attributed by Chapman Petroleum Engineering Ltd. in accordance with standards and procedures contained in the COGE Handbook. During the evaluation, Petrocapita presents its development plans to Chapman Petroleum Engineering Ltd. who, in turn, assess the merit of assigning reserves to the identified technical opportunities. Currently, Petrocapita plans to develop the majority of its proved and probable undeveloped reserves over the next several years. However, if the economic climate is not conducive to developing these reserves within this time period, Petrocapita may, in its discretion, defer the development into the future. There are a number of factors that could result in delays or the cancellation of development plans. These factors could include, but are not limited to, adverse changes in economic and technical conditions, surface access issues and the availability of services. Because of these uncertain factors, Petrocapita does not know if the potential drilling locations it has identified will ever be drilled or if it will be able to produce natural gas or oil from these or any other potential drilling locations. Any delays or cancellations in Petrocapita's development plans could reduce Petrocapita's earnings and cash flow and its business and financial condition may be materially adversely affected.

There are numerous uncertainties inherent in estimating quantities of recoverable oil reserves, including many factors beyond Petrocapita's control.

Estimates of economically recoverable petroleum and natural gas reserves and the related future net revenues are based upon a number of variables and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are based on professional judgment and classifications of reserves, which, by their nature, have a high degree of subjectivity. For those reasons, estimates of the economically recoverable petroleum and natural gas reserves attributable to any particular group of properties, classification of such reserves based on the risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary.

The reserves and recovery information contained in the Reserves Report are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by Chapman Petroleum Engineering Ltd. Such variations could be material. The Reserves Report has been prepared using certain commodity price assumptions, which are described above under the heading "*Reserves Data and Other Oil and Gas Information*". If Petrocapita realizes lower prices for oil, natural gas liquids and natural gas and if such realized prices are substituted for the price assumptions utilized in the Reserves Report, the present value of estimated future net revenues for Petrocapita's reserves and net asset value would be reduced and the reduction could be significant. The estimates in the Reserves Report are based in part on the timing and success of activities Petrocapita intends to undertake in future years. The reserves and the related estimated cash flows contained in the Reserves Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the reports.

Estimates of proved undeveloped reserves are sometimes based upon volumetric calculations and by analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

Petrocapita relies on third parties to operate certain of its productive oil and natural gas assets and have limited control over the timing of development, associated costs, or the rate of production on such non-operated acreage.

While Petrocapita operates nearly all of its production base, other companies operate the remainder of the productive oil and natural gas assets in which Petrocapita has an interest. Petrocapita has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Petrocapita's financial performance. Petrocapita's return on assets operated by others depends upon a number of factors that may be outside of Petrocapita's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Unless Petrocapita replaces its current reserves with new reserves and develops those reserves, Petrocapita's future reserves and production will decline, which would adversely affect Petrocapita.

Producing hydrocarbon reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless Petrocapita conducts successful ongoing exploitation, development and exploration activities or continually acquire properties containing reserves, its expected future reserves will decline as those reserves are produced. Petrocapita's future oil and natural gas reserves and production, and therefore its future cash flow and results of operations, are highly dependent on its success in efficiently developing and exploiting its current reserves and economically finding or acquiring additional recoverable reserves. Petrocapita may not be able to develop, exploit, find or acquire sufficient additional reserves to replace its current production. If Petrocapita is unable to replace its current production, the value of its reserves will decrease, and its business, financial condition, results of operations, cash flows and future prospects may be materially adversely affected.

Seasonal weather conditions may adversely affect Petrocapita's drilling and producing activities and other oil and natural gas operations.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access to Petrocapita's properties and, as a result, reduced operations or a cessation of operations. Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain of Petrocapita's oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity or increased costs and corresponding decreases in the demand for the goods and services of Petrocapita.

Expiration of licences and leases will have a negative effect on Petrocapita's business operations.

Certain of Petrocapita's properties are held in the form of licences and leases and working interests in licences and leases. If Petrocapita or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of Petrocapita's licences or leases or the working interests relating to a license or lease may have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Changes to environmental regulations that affect the oil and gas industry, or the failure to comply with such regulations, could adversely affect Petrocapita.

The oil and gas industry is subject to significant and complex local, provincial and federal environmental laws and regulations that provide for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well, pipeline and facility sites be remediated, abandoned and reclaimed to the satisfaction of the applicable regulatory authority. In certain circumstances, Petrocapita could also be liable for environmental damages caused by previous owners and operators. Non-compliance with such laws and regulations may result in the imposition of substantial fines and penalties, the suspension or revocation of necessary licences and authorizations to operate its properties and civil liability for pollution damage. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Petrocapita to incur costs to remedy such discharge. Although management believes that Petrocapita is in material compliance with current applicable environmental regulations, no assurance can be given that compliance with current or future environmental laws will not result in a suspension or curtailment of production or a material increase in Petrocapita's costs of production, development or exploration activities or otherwise materially adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects. For further discussion of environmental regulations governing the oil and gas industry in the areas in which Petrocapita operates, see "*Industry Conditions*" above.

Petrocapita's properties are concentrated in the Lloydminster area of Alberta and Saskatchewan, making it vulnerable to risks associated with operating in a limited geographic area.

Petrocapita's properties and production are focused in the Lloydminster area. As a result, Petrocapita may be disproportionately exposed to the impact of delays or interruptions of production caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within the specific geographic oil and natural gas producing areas in which Petrocapita's properties are located, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions on Petrocapita. Due to the concentrated nature of Petrocapita's portfolio of properties, a number of Petrocapita's properties could experience one or more of the same conditions at the same time, resulting in a relatively greater impact on Petrocapita's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the business, financial condition, results of operations, cash flows and future prospects of Petrocapita.

The marketability of Petrocapita's production is dependent upon transportation and other facilities, certain of which Petrocapita does not control. If these facilities are unavailable, Petrocapita's operations could be interrupted and its financial condition adversely affected.

The success of Petrocapita's projects and operations depends in part on the availability and successful operation of certain infrastructure that is owned and operated by third parties or joint ventures with third parties, including the following:

- pipelines for the transport of oil and natural gas;

- power transmission grids supplying and exporting electricity; and
- other third party transportation infrastructure such as roads, railways, airstrips, terminals and vessels.

For example, Petrocapita's projects will depend on the successful operation of the pipelines owned and operated by Husky Energy and Plains Midstream Pipelines**.** Any interruption in the operation of such pipelines could have a material adverse effect on Petrocapita by limiting its ability to transport oil and natural gas to market. The failure of any or all of these third parties to provide an adequate supply of such services in a timely, cost-efficient, reliable and effective manner could negatively impact Petrocapita's operations and thereby affect Petrocapita's results of operations and financial condition.

The implementation of strategies for reducing greenhouse gases may impose restrictions or costs on Petrocapita's business and may adversely affect Petrocapita.

Petrocapita's exploration and production facilities and other operations and activities emit greenhouse gases ("**GHGs**") which may subject Petrocapita to both provincial in Alberta and Saskatchewan and federal legislation regulating emissions of GHGs. Given the evolving nature of climate change regulation at both the provincial and federal level, it is not possible to predict its potential impact on Petrocapita and its operations and financial condition at this time. However, the adoption and implementation of any regulations imposing reporting obligations on, or reducing or limiting emissions of GHGs from, Petrocapita's equipment and operations could result in additional costs, which would adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects. See "*Industry Conditions*" for further details on GHG legislation.

The estimated PV-10 value of Petrocapita's proved and proved plus probable reserves will not be the same as the current market value of its estimated oil reserves.

Readers should not assume that the estimated PV-10 value of Petrocapita's proved reserves is the current market value of Petrocapita's estimated oil, NGL and natural gas reserves. NI 51-101 permits disclosure of the estimated PV-10 value of Petrocapita's proved and proved plus probable reserves using only forecast prices and costs. Actual future net cash flows from Petrocapita's oil, NGL and natural gas properties will be affected by factors such as:

- the actual prices Petrocapita receives for oil;
- the actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both Petrocapita's production and its incurrence of expenses in connection with the development and production of oil, NGL and natural gas properties will affect the timing and amount of actual future net revenues from proved and probable reserves, and thus their actual present value. In addition, the 10% discount factor Petrocapita used when calculating estimated PV-10 value may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with Petrocapita or the oil and gas industry in general. Actual future prices and costs may differ materially from those used in the present value estimates included in this prospectus, which could have a material effect on the value of Petrocapita's reserves.

Petrocapita participates in a variety of projects and may have more concentrated risk in certain areas of its operations.

Petrocapita manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Petrocapita's ability to execute projects and market oil and natural gas depends upon numerous factors beyond Petrocapita's control, including the availability of processing capacity; the availability and proximity of pipeline or other transportation capacity; the availability of storage capacity; the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or Petrocapita's ability to dispose of water used or removed from strata at a reasonable cost and within environmental regulations; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling rigs and related equipment (typically leased from third parties) in the particular areas where exploration and development activities are to be conducted; unexpected cost increases; accidents; currency fluctuations; changes in regulations;

the availability and productivity of skilled labour; and the regulation of the oil and gas industry by various levels of government and governmental agencies. As a result of these factors, Petrocapita could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

The amount of oil and natural gas that Petrocapita can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering and processing facilities, pipeline systems and railway lines.

Petrocapita delivers its products through gathering, processing and pipeline systems, some of which it does not own, and by rail. The amount of oil and natural gas that Petrocapita can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems, and railway lines. The lack of availability of capacity in any of the gathering facilities, pipeline systems, railway lines, and in particular the processing facilities used by Petrocapita, could result in it being unable to realize the full economic potential of its production or in a reduction of the price offered for its production. Although pipeline expansions and new projects are ongoing they are in various stages of review and approval and such regulatory approvals may not be secured on a timely basis or at all. The lack of firm pipeline capacity affects the oil and gas industry and may limit Petrocapita's ability to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased significantly and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Due to the current shortage of pipeline capacity, Canadian oil and natural gas producers have turned to shipping crude oil by rail as a short-term alternative. However, as the amount of crude oil shipped by rail has increased, there have been a number of regulatory and safety developments which may affect the cost and availability of crude oil rail shipments moving forward. Following major accidents in Lac-Megantic, Québec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Safety Board issued recommendations to Transport Canada, the responsible Canadian federal ministry, to improve the safe transportation of crude oil by rail. In response, the federal Transport Minister announced an order removing approximately 5,000 DOT-111 tanker rail cars from Canadian railways within a short period of time, with another 65,000 DOT-111 tanker rail cars to be removed or retrofitted within 3 years, and the federal Transport Minister plans to establish speed limits of 50 miles-per-hour or less for trains carrying 20 cars or more of crude oil or ethanol in areas that are built up or are near drinking water. Further, Transport Canada has unveiled a proposal that would require tank cars used to haul crude oil to employ thicker steel, thermal protection, full shields and more protection over the valves. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of oil by rail.

A portion of Petrocapita's production may, from time to time, be processed through facilities owned by third parties and over which it does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on Petrocapita's ability to process its production and deliver the same for sale.

Unforeseen title defects in Petrocapita's properties may result in a loss of rights to production and reserves.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Petrocapita's claim. Petrocapita's actual interest in properties may, therefore, vary from Petrocapita's records. Such a defect in the chain of title could have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects. There may be valid challenges to title, or proposed legislative changes that affect title, to the oil and natural gas properties Petrocapita controls that, if successful or made into law, could impair Petrocapita's activities on them and result in a reduction of the revenue received by Petrocapita.

Legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect Petrocapita's production.

Petrocapita uses hydraulic fracturing in its operations. Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to fracture such formations and thereby stimulate oil and natural gas production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Negative public perception of hydraulic fracturing has put pressure on governments to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Petrocapita's operations and increase its costs. It is believed that the trend in environmental legislation and regulation in Alberta and Saskatchewan will continue towards stricter standards in regards to hydraulic fracturing. For further information see "*Industry Conditions*" above. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase Petrocapita's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Petrocapita is ultimately able to produce from its reserves.

Petrocapita operates in heavy oil production, exploration and development in the Alberta and Saskatchewan Mannville heavy oil play of western Canada and expansion into new activities or geographic areas may increase its risk exposure.

The operations and expertise of Petrocapita's management are currently focused primarily on heavy oil production, exploration and development in the Mannville formation. In the future Petrocapita may acquire or move into new industry-related activities or new geographical areas or may acquire different energy-related assets, which may require substantial management effort, time and resources and may divert management's focus and resources from current operational matters. As a result of venturing into new activities or new areas, Petrocapita may face new or unexpected risks or alternatively may significantly increase Petrocapita's exposure to one or more existing risk factors, which may in turn result in Petrocapita's future operational and financial conditions being adversely affected.

Aboriginal claims could have an adverse effect on Petrocapita and its operations.

Aboriginal peoples have claimed Aboriginal title and rights to a substantial portion of western Canada. Petrocapita are not aware that any claims have been made in respect of its assets. However, if a claim arose and was successful, such claim could have a material adverse effect on Petrocapita and its business, financial condition, results of operations, cash flows and future prospects. The duties owed to Aboriginal peoples by the Canadian federal and provincial governments have the potential to affect federal and provincial regulatory practices and framework and affect Petrocapita's ability to obtain permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. Opposition by Aboriginal peoples may also negatively impact Petrocapita in terms of public perception, diversion of management time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in Petrocapita's operations, or court-ordered relief impacting Petrocapita's operations.

Petrocapita may be unable to implement new technologies in a timely and economic manner.

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before Petrocapita. There can be no assurance that Petrocapita will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by Petrocapita or implemented in the future may become obsolete. If Petrocapita is unable to utilize the most advanced commercially available technology, its business, financial condition, results of operations, cash flows and future prospects could be materially adversely affected.

Risks Related to Petrocapita's Business, Financial Matters and Tax Matters

Loss of Petrocapita's key management and other personnel, or an inability to attract, retain and motivate such management and other personnel, could negatively impact Petrocapita's business.

Successfully developing and commercializing oil and natural gas interests depends on a number of factors, including the technical skill of the personnel involved. Petrocapita's success will be, in part, dependent on the performance of its key managers and consultants. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of Petrocapita's managers and consultants. Failure to retain the managers and consultants, or to attract or retain additional key personnel, with the necessary skills and experience could have a materially adverse impact upon Petrocapita's growth and profitability. Petrocapita does not carry key person insurance.

The labour force in the specific areas in Alberta and Saskatchewan in which Petrocapita's properties are located is limited and there can be no assurance that all of the required employees with the necessary expertise will be available. Similar projects or expansions will proceed in the same area during the same time frame as Petrocapita's projects. Petrocapita's projects will compete with these other projects for experienced employees and such competition may result in increases to compensation paid to such personnel or in a lack of qualified personnel. Increased labour costs could materially adversely affect Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Geopolitical risks may adversely impact Petrocapita.

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by Petrocapita. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of Petrocapita's net production revenue.

Variations in foreign exchange rates and interest rates could adversely affect Petrocapita's financial condition.

Most of Petrocapita's revenues are based on the U.S. dollar, since revenue received from the sale of oil is generally referenced to a price denominated in U.S. dollars, while Petrocapita incurs most of its operating and other costs in Canadian dollars. Petrocapita is therefore exposed to exchange rate fluctuations between the U.S. dollar and the Canadian dollar. Any strengthening of the Canadian dollar relative to the U.S. dollar could negatively impact Petrocapita's operating margins and cash flow. In addition, as Petrocapita reports its operating results in Canadian dollars, fluctuations in product pricing and in the rate of exchange between the U.S. dollar and Canadian dollar affect Petrocapita's reported results.

To the extent that Petrocapita engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which it may contract.

An increase in interest rates could result in a significant increase in the amount Petrocapita pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, cash available for distributions and could negatively impact the market price of its Trust Units.

Petrocapita may require additional financing in order to carry out its acquisition, exploration and development activities and there can be no assurance that such financing will be available to Petrocapita.

Petrocapita's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, Petrocapita may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, Petrocapita's access to additional financing may be affected.

Because of global economic volatility, Petrocapita may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause Petrocapita to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Petrocapita's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will

affect Petrocapita's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, Petrocapita's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition, results of operations, cash flows and future prospects may be affected materially and adversely as a result. In addition, the future development of Petrocapita's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for Petrocapita's capital expenditure plans may result in a delay in development or production on Petrocapita's properties.

Petrocapita's acquisition, exploration, development and production projects require substantial capital expenditures. Petrocapita may be unable to obtain required capital or financing on satisfactory terms, which could prevent Petrocapita from achieving its business plan.

Petrocapita anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, Petrocapita's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- Petrocapita's creditworthiness (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and Petrocapita's securities in particular.

Further, if Petrocapita's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future acquisitions. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Petrocapita. The inability of Petrocapita to access sufficient capital for its operations could have a material adverse effect on its business, financial condition, results of operations, cash flows and future prospects.

Instability in global financial markets may cause significant volatility in commodity prices and hinder Petrocapita's ability to obtain equity or debt financing.

Recent market events and conditions, including the significant drop in oil prices, disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions have negatively impacted credit markets and caused stock markets to experience significant volatility. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC, events in the Ukraine, ongoing global credit and liquidity concerns and Middle East political concerns. This volatility may in the future affect Petrocapita's ability to obtain equity or debt financing on acceptable terms. To the extent that external sources of capital become limited, unavailable or available on onerous terms, Petrocapita's ability to pursue acquisitions, make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition, results of operations, cash flows and future prospects may be materially and adversely affected as a result.

Failure to realize anticipated benefits of acquisitions and dispositions may have a material adverse effect on Petrocapita's business.

Petrocapita makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends, in part, on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as Petrocapita's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with Petrocapita's business and operations. There can be no assurance that Petrocapita will be able to successfully realize the anticipated benefits of any acquisition. Further, the costs involved and time required to realize the anticipated benefits of acquisitions may exceed those benefits and may detract from available resources that could have been committed elsewhere for general benefit. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Assets determined by management to be non-core are periodically disposed of so that Petrocapita can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Petrocapita, if disposed of, could be expected to realize less than their carrying value on the financial statements of Petrocapita.

Additionally, such acquisitions may result in Petrocapita's capitalization and results of operations changing significantly. Investors will not have the opportunity to evaluate the economic, financial and other relevant information that Petrocapita will consider in determining the application of its funds and other resources with respect to such acquisitions.

Competition in the oil and gas industry is intense, making it more difficult for Petrocapita to acquire properties, market oil and natural gas and secure trained personnel.

The Canadian and international oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of property leases and the distribution and marketing of petroleum products. Some of the producers have competitive operating costs and some of them have greater resources to source, attract and retain the personnel, materials and services that Petrocapita requires to conduct its operations. The oil and gas industry also competes with other industries in supplying energy, fuel and related products to consumers. Some of these industries benefit from less regulation, lower taxes and higher subsidies. In addition, certain of these industries are less capital intensive.

Other companies may announce plans to enter the petroleum business or expand existing operations. Expansion of existing operations and development of new projects could significantly increase the supply of commodities in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of oil and, accordingly, Petrocapita's business, financial condition, results of operations, cash flows and future prospects. In addition, expansion of existing operations and development of new projects could materially increase the costs of inputs such as labour, equipment, materials or services which, in turn, may have a material adverse effect on Petrocapita's results of operations and financial condition.

Oil and natural gas exploration and development activities are dependent on a range of operational and non-operational factors of production. These include drilling rigs, related equipment and qualified personnel, processing facilities and refineries, transportation facilities and other equipment, many of which are controlled by third parties and which Petrocapita has no assurance of obtaining access to. Petrocapita competes with a substantial number of other organizations for access to these factors, many of which will have greater technical and financial resources than Petrocapita. There is no assurance that Petrocapita will obtain or maintain such access and at an economically viable cost, in a sufficient quantity or at all. Such competition may delay Petrocapita's exploration and development activities.

Certain of Petrocapita's directors and officers are involved in other oil and natural gas interests and have the ability to take actions that could conflict with Petrocapita's interests.

Some of Petrocapita's directors and officers are engaged and will continue to be engaged in the oil and natural gas business on their own behalf and on behalf of others, and situations may arise where the directors or officers will acquire and hold interests in businesses that compete directly or indirectly with Petrocapita or that supply

Petrocapita with goods and services. These directors, officers or shareholders may also pursue acquisition opportunities that may be complementary to, or competitive with, Petrocapita's business, and as a result those acquisition opportunities may not be available to Petrocapita. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by ABCA which require a director or officer of a corporation who is party to a material contract or proposed material contract with Petrocapita to disclose such director's or officer's interest and, with respect to a director, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Trustees, Directors and Executive Officers – Conflicts of Interest*".

The outcome of outstanding, pending or future legal proceedings could have a material adverse effect on Petrocapita's business.

In the normal course of Petrocapita's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Petrocapita and, as a result, could have a material adverse effect on its business, financial condition, results of operations, cash flows and future prospects.

Non-IFRS Measures

This prospectus makes reference to certain non-IFRS measures, including operating netback and net debt. These non-IFRS measures and other financial estimates of management are based upon variable components. The non-IFRS measures do not have any standardized meaning prescribed by IFRS and as such may not be directly comparable to measures for other companies where similar terminology is used. There can be no assurance that these components and future calculations of non-IFRS measures will not vary. See "*Notice to Investors – Non-IFRS Measures*".

Petrocapita is susceptible to the potential difficulties associated with significant growth and expansion.

Petrocapita may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The effective management of the growth of Petrocapita will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of Petrocapita to deal with this growth may have a material adverse effect on its business, financial condition, results of operations, cash flows and future prospects.

Petrocapita's internal controls may not be adequate.

Effective internal controls are necessary for Petrocapita to provide reliable financial reports and to help prevent fraud. Although Petrocapita has undertaken and will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those that may become applicable to it under Canadian securities laws, Petrocapita cannot be certain that such measures will ensure that it will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Petrocapita's results of operations or cause it to fail to meet its reporting obligations. Additionally, implementing and monitoring effective internal controls can be costly. If Petrocapita or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Petrocapita's financial statements and harm the value or price of the Trust Units.

Income tax laws or other laws or government incentive programs or regulations relating to Petrocapita's industry may in the future be changed or interpreted in a manner that adversely affects Petrocapita.

Petrocapita has filed all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. Notwithstanding this, such returns are subject to reassessment by the applicable tax authority and it is possible that the tax authorities could successfully challenge any prior transactions and tax filings of Petrocapita. In the event of a successful reassessment, Petrocapita may be subject to higher than expected past or future income tax liability as well as potentially interest and penalties.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects Petrocapita's business, financial condition, results of operations, cash flows and future prospects. Furthermore, there can be no assurance that the relevant tax authorities will agree with Petrocapita's calculation of its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of Petrocapita.

Petrocapita's risk management activities and hedging strategies may negatively impact Petrocapita's income and its financial condition.

Petrocapita may use hedging instruments to manage its exposure to fluctuations in commodity prices, exchange rates and interest rates. If Petrocapita engages in any such hedging activities, it will be exposed to credit-related losses in the event of non-performance by counterparties to the physical or financial instruments. Additionally, if commodity prices, interest rates or exchange rates increase above or decrease below those levels specified in any future hedging agreements, such hedging agreements may prevent Petrocapita from realizing the full benefit of such increases or decreases. In addition, any future commodity hedging arrangements could cause Petrocapita to suffer financial loss if it is unable to produce sufficient quantities of the commodity to fulfill its obligations, if it is required to pay a margin call on a hedge contract or if it is required to pay royalties based on a market or reference price that is higher than Petrocapita's fixed ceiling price.

To the extent that risk management activities and hedging strategies are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

Petrocapita may incur substantial losses and be subject to substantial liability claims as a result of its operations. Additionally, Petrocapita may not be insured for, or its insurance may be inadequate to protect Petrocapita against, these risks.

Petrocapita's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards.

Although Petrocapita maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, Petrocapita may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to Petrocapita. The occurrence of a significant event that Petrocapita is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on Petrocapita's business, financial condition, results of operations, cash flows and future prospects.

In addition, Petrocapita's wells and other facilities could be subject to a terrorist attack or physical sabotage, which may also have a material adverse effect on Petrocapita insofar as any such action caused property damage or personal harm or disrupted operations. Petrocapita does not have insurance to protect against such risks.

A failure of or error caused by Petrocapita's information and computer systems could adversely affect Petrocapita's business.

Petrocapita is heavily dependent on its information systems and computer based programs, including its well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in its hardware or software network infrastructure, possible consequences include a loss of communication links or reliable information, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence that results in a loss of data or is not resolved within a short period of time could have a material adverse effect on Petrocapita's business.

Petrocapita may be required to pay cash income taxes sooner than it currently anticipates, reducing Petrocapita's available cash.

Based on the tax pools of Petrocapita as at December 31, 2014, its anticipated capital spending profile and forecasted commodity prices in the Reserves Report, Petrocapita expects to pay no cash taxes in 2015. Should there be a lower level of capital expenditures than those contained in the Reserves Report, or should the assumptions used by Petrocapita prove to be inaccurate, Petrocapita may be required to pay cash income taxes sooner than anticipated, which will reduce cash available to it.

Risks Related to an Investment in Trust Units

There is no prior public market for the Trust Units.

No public market currently exists for the Trust Units. If an active public market does not develop or is not maintained, investors may have difficulty selling their Trust Units.

The price of the Trust Units may be volatile.

The market price for the Trust Units may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond Petrocapita's control, including the following:

- actual or anticipated fluctuations in Petrocapita's results of operations;
- recommendations by securities research analysts;
- changes in the economic performance or market valuations of other companies or business entities that investors deem comparable to Petrocapita;
- the loss of executive officers and other key personnel of Petrocapita;
- sales or perceived sales of additional Trust Units;
- significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving Petrocapita or its competitors; and
- trends, concerns, technological or competitive developments, regulatory changes and other related issues in Petrocapita's business segments or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the value or price of the Trust Units may decline even if Petrocapita's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values which may result in impairment losses.

Further sales of Trust Units may dilute a Unitholder's position in Petrocapita.

Petrocapita may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Trust or its subsidiaries (including the Partnership or the Corporation). Such actions may dilute a Unitholder's position in the Trust specifically or in Petrocapita generally. See "*Risk Factors – Risks Related to Petrocapita's Business, Financial Matters and Tax Matters – Petrocapita's acquisition, exploration, development and production projects require substantial capital expenditures. Petrocapita may be unable to obtain required capital or financing on satisfactory terms, which could prevent Petrocapita from achieving its business plan*".

Petrocapita's forward-looking statements may be inaccurate, actual results may vary significantly from the historical and forecasted, and those variations may be material.

This prospectus contains forward-looking statements. By its nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. As a result, there can be no assurance that the assumptions reflected in such estimates will prove to be accurate. Actual results of Petrocapita

in the future may vary significantly from the historical and forecasted, if any, results and those variations may be material. There is no representation by Petrocapita that actual results achieved by it in the future will be the same, in whole or in part, as those included in this prospectus.

The factors discussed in this section entitled "Risk Factors" and in the section above entitled "Forward-Looking Statements" must be weighed carefully, and prospective investors must not place undue reliance on the forward-looking statements contained in this prospectus.

See "*Forward-Looking Statements*" above.

Risks Relating to the Trust Structure or Trust Units

Distributions are discretionary and may be variable.

The only outstanding Units of the Trust are Trust Units, which do not carry any fixed distribution entitlement.

The Trust may in the future make distributions of available funds to holders of Trust Units, but has no obligation to do so. Holders of Trust Units are entitled to receive non-cumulative distributions only if, as and when declared by the Trustees in accordance with the provisions of the Declaration of Trust. **Any such distributions are discretionary and there is no assurance that they will be declared on a regular or consistent basis or at all.**

The ability of the Trust to make distributions to Unitholders is and will continue to be a function of numerous and varied factors affecting Petrocapita's financial position, including: commodity prices; production levels; operating costs; royalty and tax burdens; working capital requirements; capital expenditure requirements (both sustaining and expansion) for the purchase of property, plant and equipment; current and potential future environmental liabilities; debt service requirements, covenants and obligations; the impact of interest rates and/or foreign exchange rates; growth of the general economy; the price of crude oil and natural gas; and the number of Trust Units issued and outstanding – as well as decisions of the Board and Management of the Administrator and General Partner regarding reinvestment in Petrocapita's oil and gas operations and business generally. Cash distributions, where made, may not be sustained, and may be increased, reduced or suspended, or eliminated entirely, depending on Petrocapita's operations and the performance of its assets. The value of Trust Units may deteriorate if the Trust does not or is unable to make cash distributions generally or at a level that meets investor expectations, and that deterioration may be material.

See "*Declaration of Trust – Distribution Rights; Distributable Cash*" and "*Distribution Policy*" above.

Risks associated with the taxation of the Trust and its Subsidiaries could negatively affect the value of the Trust Units.

There can be no assurance that the Trust will not cease to qualify as a "mutual fund trust" under the Tax Act.

To qualify as a "mutual fund trust" for purposes of the Tax Act, the Trust must continuously satisfy certain requirements as to the nature of its undertakings (primarily that it must restrict its activities to the investment of funds), its ability to distribute Trust Units to the public, the dispersal of ownership of its Trust Units and the requirement that, unless it meets certain exceptions, it must not be reasonable to consider that it was established or is maintained primarily for the benefit of non-Canadian holders.

If the Trust were to cease to qualify as a "mutual fund trust", Trust Units held by Unitholders who are not resident in Canada for the purposes of the Tax Act ("**Non-Canadian Holders**") would become "taxable Canadian property" under the Tax Act. These Non-Canadian Holders would be subject to Canadian income tax on any gains realized on a disposition of the Units held by them unless they were exempt under an income tax convention, and Non-Canadian Holders may be subject to certain notification and withholding requirements on a disposition of their Trust Units. In addition, the Trust would be taxed on certain types of income distributed to Unitholders. Payment of this tax may have adverse consequences for some Unitholders, particularly Non-Canadian Holders and residents of Canada that are otherwise exempt from Canadian income tax.

In addition, there can be no assurance that income tax laws related to the status of "mutual fund trusts", the taxation of "mutual fund trusts", or other matters will not be changed in a manner which adversely affects Unitholders.

See also "*Taxation of Specified Investment Flow-Through Trusts*".

Trust Units have certain risks not associated with traditional investments in the oil and gas business.

The Trust Units share some similar economic attributes as common shares of a corporate issuer, but do not represent a traditional equity investment in an oil and gas business and should not be viewed as shares of a corporation. The Trust Units represent fractional beneficial interests in the Trust.

Unlike shareholders of a corporation incorporated under the *Canada Business Corporations Act* ("**CBCA**") or similar provincial business corporations legislation, whose rights include those provided by the CBCA or such similar statutes, the rights of Unitholders – as investors in the Trust and holders of Trust Units – are established and governed by the Declaration of Trust. As such, Unitholders do not have any of the statutory rights normally associated with ownership of shares of a corporation. The Declaration of Trust provides for Unitholder rights that are analogous to certain of the statutory rights provided under the CBCA, such as a requirement that (with certain exceptions) Unitholders approve any sale of all of substantially all of the assets of the Trust, and elect Trustees on an annual basis. See "*Declaration of Trust – Meetings of Unitholders*". The matters in respect of which Unitholder approval is required under the Declaration of Trust are less extensive, however, than those for which shareholder approval would be required under the CBCA. Amendments to the articles of a CBCA corporation, for example, must be approved by shareholders, whereas the Trustees may amend the Declaration of Trust for any purpose provided that, in their opinion, the rights of the Unitholders are not materially prejudiced thereby. See "*Declaration of Trust – Amendments*".

Unitholders do not have a dissent right akin to what is available to shareholders under the CBCA, who are entitled to receive from the corporation the 'fair value' of their shares in the event of certain fundamental changes affecting the corporation (such as an amalgamation, a continuance under the laws of another jurisdiction, or a sale of all or substantially all of its property). Unitholders seeking to exit their investment in the Trust must either sell their Units to a third party or exercise their redemption rights as described above under "*Declaration of Trust – Redemption Rights*". Unitholders similarly do not have recourse to the statutory oppression remedy that is available to shareholders under the CBCA in the event of action or conduct that is oppressive or unfairly prejudicial to, or that disregards the interests of, shareholders. The CBCA also provides a means by which shareholders may, with leave of a court, bring "derivative" actions in the name and on behalf of the corporation or any of its subsidiaries, or intervene in an action to which the corporation or any such subsidiary is a party, for the purpose of prosecuting, defending or discontinuing the action on its behalf. No similar right is provided for under the Declaration of Trust.

The Trust's only material assets are the outstanding shares of the Corporation and the outstanding LP Units. The value of a Trust Unit will be a function of, among other things, the underlying assets of Petrocapita held by the Partnership, the anticipated net earnings (and earning potential) of Petrocapita's business, management's ability to effect long-term growth in the value of the Partnership and other entities now or hereafter owned directly or indirectly by the Trust, and any cash distributions paid by the Trust to Unitholders. Petrocapita's value is sensitive to a variety of conditions, including interest rates, the growth of the general economy, the price of crude oil and natural gas and changes in law.

Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. The Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

The Trust is not a legally recognized entity within the relevant definitions of the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and, in some cases, the *Winding Up and Restructuring Act* (Canada). As a result, in the event a restructuring of the Trust were necessary, the Trust would not be able to access the remedies available thereunder. In the event of any such restructuring, the position of Unitholders may be different than that of the shareholders of a corporation.

Petrocapita's debt service obligations may limit the amount of cash available for distributions.

The Trust and its affiliates may, from time to time, finance some or a significant portion of their growth (either from acquisitions or capital expenditure additions) and operations through debt. Amounts paid in respect of interest and principal on debt incurred by Petrocapita and its affiliates may impair Petrocapita's ability to satisfy its other obligations. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to service debt. This may result in lower levels of cash available for reinvestment in Petrocapita's business or for distribution by the Trust to its Unitholders. Moreover, subordination agreements or other debt obligations could limit or preclude distributions altogether.

Unitholders may have liability beyond their investment in limited circumstances.

The Declaration of Trust generally provides that no Unitholder or beneficial Unitholder, in their capacity as such, will be subject to any liability in connection with the Trust or its obligations and affairs or for any act or omission of the Trustees, provided that in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, the Trust's assets. In addition, the Declaration of Trust provides that no Unitholder is liable to indemnify the Trustee or any other person for any liabilities incurred by the Trustee, including with respect to taxes payable by the Trust or the Trustee, and all such liabilities will be enforced only against, and will be satisfied only out of, the Trust's assets.

Effective July 1, 2004, the Alberta government implemented section 2(1) of the *Income Trust Liability Act* (Alberta), which specifically provides that beneficiaries, as beneficiaries, are not liable for any act, default, obligation or liability of the trustee of any Alberta income trust. The Trust is an Alberta income trust. However, a Unitholder who has been actively involved in the direction or management of the Trust beyond voting Trust Units at Unitholder meetings may incur liability beyond their investment.

In conducting its affairs, the Trust has incurred and will in the future incur obligations and liabilities. Although the Declaration of Trust provides that, in respect of any obligations or liabilities incurred by the Trust (or a Trustee or the Administrator on behalf of the Trust), the Trustees and the Administrator will make all reasonable efforts to include, as a specific term of any such obligation or liability, a contractual provision to the effect that such obligations or liabilities are not personally binding upon the Trustees, the Administrator or any Unitholder, a contractual modification to such effect may not be obtained in all cases. To the extent that any such obligations or liabilities are not satisfied by Petrocapita, there is a risk that a Unitholder may be held personally liable for obligations of the Trust where the same is not expressly disavowed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no material legal proceedings to which Petrocapita is or was a party, or of which any of its property is or was the subject, since the beginning of Petrocapita's most recent financial year, nor are any such legal proceedings known to Petrocapita to be contemplated, in each case involving a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of Petrocapita.

There are no: (a) penalties or sanctions imposed against Petrocapita by a court relating to provincial and territorial securities legislation or by a securities regulatory authority since Petrocapita's inception; (b) other penalties or sanctions imposed by a court or regulatory body against Petrocapita necessary for this prospectus to contain full, true and plain disclosure of all material facts relating to the Trust Units; and (c) settlement agreements Petrocapita entered into before a court relating to provincial and territorial securities legislation or with a securities regulatory authority since Petrocapita's inception.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as otherwise set out herein, there is no material interest, direct or indirect, of any: (a) director or executive officer of Petrocapita; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Petrocapita's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within three years before the date of this prospectus that has materially affected or is reasonably expected to materially affect Petrocapita.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Trust are Collins Barrow Calgary LLP, Chartered Accountants, Calgary, Alberta, which firm has served as the auditors of the Trust since 2010.

Alliance Trust Company, Calgary, Alberta, is the transfer agent and registrar for the Trust Units.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that Petrocapita has entered into prior to the date of this prospectus and can reasonably be regarded as currently material, are the Declaration of Trust, the Administration Agreement and the LP Agreement. See "*Declaration of Trust*", "*Administration Agreement*", and "*Limited Partnership Agreement*".

INTEREST OF EXPERTS

No person or company whose profession or business gives authority to a report, valuation, statement or opinion made by such person or company and who is named in this prospectus as having prepared or certified a part of this prospectus, or a report, valuation, statement or opinion described in this prospectus, has received or shall receive a direct or indirect interest in any securities or other property of the Trust or any associate or affiliate of the Trust, including the Partnership and the Corporation.

As at the date hereof, the designated professionals of Chapman Petroleum Engineering Ltd., independent engineering consultants to Petrocapita, as a group, directly or indirectly own, through registered or beneficial interests, less than 1% of any class of outstanding securities of the Trust or any associate or affiliate of the Trust, including the Partnership and the Corporation.

Collins Barrow Calgary LLP has advised they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

APPENDIX A

FINANCIAL STATEMENTS OF THE TRUST

Following are:

- the audited consolidated financial statements of Petrocapita Income Trust (the "**Trust**") for the financial years ended December 31, 2014, 2013 and 2012, respectively, including the notes thereto and auditors' reports thereon; and

- the unaudited consolidated financial statements of the Trust for the three and six month periods ended June 30, 2015 and 2014, including the notes thereto.

See Appendix B for related management's discussion and analysis of the Trust for the financial years ended December 31, 2014 and 2013, respectively, and the six month period ended June 30, 2015.

Petrocapita Income Trust

Condensed Interim Consolidated Financial Statements
For the three and six months ended
June 30, 2015 and 2014

(in Canadian dollars)

(unaudited)

Petrocapita Income Trust
Condensed Interim Consolidated Balance Sheets

(in Canadian dollars)

(unaudited)

	Notes	June 30, 2015	December 31, 2014
Assets			
Current assets			
Cash		$ 1,349,041	$ 2,598,148
Accounts receivable	15(b)	552,595	800,052
Note receivable	4	13,078	21,790
Prepaid expenses and deposits		27,116	99,712
		1,941,830	3,519,702
Non-current assets			
Property and equipment	5,6	30,366,373	26,506,444
Exploration and evaluation assets	7	1,338,733	1,338,733
		$ 33,646,936	$ 31,364,879
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	15(c)	$ 1,118,965	$ 1,374,927
Current portion of Preferred Units	11	-	1,572,195
		1,118,965	2,947,122
Non-current liabilities			
Decommissioning provision	8	8,899,418	6,063,703
Debenture	9	460,000	-
Convertible debenture	10	194,100	-
Preferred Units	11	-	28,611,979
		10,672,483	37,622,804
Unitholders' Equity (Deficiency)			
Deficit		(14,417,340)	(13,183,124)
Common Units	12	37,368,608	3,571,402
Equity component of convertible debentures	10	23,185	-
Equity component of Preferred Units	11	-	3,353,797
		22,974,453	(6,257,925)
		$ 33,646,936	$ 31,364,879

Commitments (note 17)

See accompanying notes to the condensed interim consolidated financial statements.

Approved by the Trustees
(signed) "Alex Lemmens", Trustee
(signed) "Richard Mellis", Trustee

Petrocapita Income Trust

Condensed Interim Consolidated Statements of Operations and Comprehensive Income (Loss)

(in Canadian dollars)

(unaudited)

		Three months ended June 30,		Six months ended June 30,	
	Notes	2015	2014	2015	2014
Revenue					
Petroleum revenue		$ 1,007,716	$ 2,910,949	$ 1,882,746	$ 5,626,214
Water disposal revenue		21,182	83,814	37,797	134,424
Royalties		(95,905)	(569,069)	(181,897)	(967,540)
		932,993	2,425,694	1,738,646	4,793,098
Expenses					
Production and transportation		716,945	1,403,305	1,355,733	3,046,530
General and administrative	16	199,750	192,884	434,916	342,924
Depletion	5	305,727	595,899	738,079	1,238,716
		1,222,422	2,192,088	2,528,728	4,628,170
Operating income (loss)		(289,429)	233,606	(790,082)	164,928
Finance expense, net	13	(29,687)	(863,912)	(905,310)	(1,702,325)
Gain on sale of property and equipment	5,6(i)	70,734	-	70,734	-
Gain on asset acquisition	6(ii)	390,442	-	390,442	-
Gain on sale of exploration and evaluation assets	7	-	-	-	143,262
Net income (loss) and comprehensive loss		$ 142,060	$ (630,306)	$ (1,234,216)	$ (1,394,135)

See accompanying notes to the condensed interim consolidated financial statements.

Petrocapita Income Trust

Condensed Interim Consolidated Statements of Changes in Unitholders' Equity (Deficiency)

(in Canadian dollars)

(unaudited)

	Notes	Number of Common Units	Common Units Stated Value	Equity Component of Preferred Units	Equity Component of Convertible Debentures	Deficit	Total Unitholders' Equity (Deficiency)
Balance at December 31, 2013		5,843,357	$ 3,571,402	$ 3,241,545	$ -	$ (9,246,287)	$ (2,433,340)
Issuance of Preferred Units	11	-	-	52,766	-	-	52,766
Loss and comprehensive loss for the period		-			-	(1,394,135)	(1,394,135)
Balance at June 30, 2014		5,843,357	3,571,402	3,294,311	-	(10,640,422)	(3,774,709)
Balance at December 31, 2014		5,843,357	3,571,402	3,353,797	-	(13,183,124)	(6,257,925)
Redemption of Preferred Units	11	-	-	(4,698)	-	-	(4,698)
Issuance of Preferred Units	11	-	-	30,622	-	-	30,622
Conversion of Preferred Units into Common Units	11	1,103,888,605	33,797,206	(3,379,721)	-	-	30,417,485
Issuance of convertible debenture	10	-	-	-	23,185	-	23,185
Loss and comprehensive loss for the period		-	-	-	-	(1,234,216)	(1,234,216)
Balance at June 30, 2015		1,109,731,962	$ 37,368,608	$ -	$ 23,185	$ (14,417,340)	$ 22,974,453

See accompanying notes to the condensed interim consolidated financial statements.

Petrocapita Income Trust
Condensed Interim Consolidated Statement of Cash Flows
(in Canadian dollars)
(unaudited)

	Notes	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Cash provided by (used in):					
Cash flows from operating activities					
Income (loss) for the period		$ 142,060	$ (630,306)	$ (1,234,216)	$ (1,394,135)
Adjustments for:					
Depletion	5	305,727	595,899	738,079	1,238,716
Distribution to Preferred Unitholders	13	162	835,204	847,730	1,654,472
Accretion of decommissioning provision	13	33,122	31,030	67,510	62,578
Accretion of convertible debenture	10	285	-	285	
Interest on note receivable	4	(105)	-	(288)	-
Bad debt expense		10,427	-	(49,379)	
Deficiency (excess) of carrying value over redemption of preferred units	13	(4,645)	(5,150)	(4,698)	(5,150)
Gain on asset acquisition	6(ii)	(390,442)	-	(390,442)	
Gain on sale of property and equipment	5,6(i)	(70,734)	-	(70,734)	-
Gain on sale of exploration and evaluation assets	7	-	-	-	(143,262)
Changes in non-cash working capital	14	(242,565)	(186,666)	221,715	(950,936)
Net cash provided by (used in) operating activities		(216,708)	640,011	125,562	462,283
Cash flows used in investing activities					
Additions to property and equipment	5	(252,327)	(565,240)	(525,431)	(878,560)
Additions to exploration and evaluation assets	7	-	(76,504)	-	(76,504)
Proceeds from disposition of exploration and evaluation assets		-	-	-	143,262
Changes in non-cash working capital		240,622	1,096,068	248,105	535,140
Net cash used in investing activities		(11,705)	454,324	(277,326)	(276,662)
Cash flows used in financing activities					
Redemption of Preferred Units		(15,000)	(7,500)	(15,472)	(7,500)
Preferred Unit distributions paid		(542,043)	(496,808)	(1,090,871)	(1,042,721)
Repayments of note receivable		4,500	4,500	9,000	9,000
Net cash used in financing activities		(552,543)	(499,808)	(1,097,343)	(1,041,221)
Change in cash		(780,956)	594,527	(1,249,107)	(855,600)
Cash, beginning of period		2,129,997	3,119,059	2,598,148	4,569,186
Cash, end of period		$ 1,349,041	$ 3,713,586	$ 1,349,041	$ 3,713,586

See accompanying notes to the condensed interim consolidated financial statements.

1. General business description

Petrocapita Income Trust (the "Trust") was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a diversified portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "Partnership"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

The Partnership is managed by Petrocapita GP I Ltd. (the “General Partner”).

The address and principal place of business of the Trust is #2210, 8561 – 8A Avenue SW, Calgary, Alberta, T3H 0V5.

The beneficiaries of the unincorporated Trust are the unitholders. The condensed interim consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the *Income Tax Act* (Canada), the Trust is subject to income taxes only on income that is not distributed or distributable to the unitholders. The Trust, to date, has no undistributed income. As a limited partnership, the income tax consequences of the Limited Partnership and ultimately those of the Trust are deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability is reflected in the condensed interim consolidated financial statements.

These condensed interim consolidated financial statements were approved by the trustees on September 21, 2015.

2. Basis of preparation

(a) Statement of compliance

The condensed interim consolidated financial statements were prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and Canadian generally accepted accounting principles (GAAP) as applicable to interim financial statements, including International Accounting Standard (IAS) 34, *Interim Financial Reporting*, and should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2014, which were prepared in accordance with IFRS. The disclosure provided is incremental to that included with the annual consolidated financial statements. Certain information and disclosure included in the notes to the annual consolidated financial statements is condensed in the interim financial statements or disclosed only on an annual basis.

(b) Reporting entity

The condensed interim consolidated financial statements of the Trust as at and for the three and six months ended June 30, 2015 comprise the Trust and its two subsidiaries, the Partnership and the General Partner.

(c) Basis of measurement

The condensed interim consolidated financial statements have been prepared on the historical cost basis except for the following:

(i) Derivative financial instruments are measured at fair value; and

(ii) Financial instruments designated as "fair value through income (loss)".

(d) Functional and presentation currency

These condensed interim consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Trust and its subsidiaries.

(e) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the condensed interim consolidated financial statements and the reported amounts of revenues and expenses during the three and six months ended June 30, 2015. By their nature, estimates are subject to estimation uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

In preparing these condensed interim consolidated financial statements, the significant estimates and judgments made by management in applying the Trust's accounting policies and the key sources of estimation uncertainty were the same as those applicable to the consolidated financial statements for the year ended December 31, 2014, except that the equity portion of convertible debentures is based on management's estimate of the interest rate the Trust would pay for non-convertible debt with similar terms.

3. Significant accounting policies

The accounting policies followed in these condensed interim consolidated financial statements are consistent with those for the year ended December 31, 2014, except as follows:

During the three months ended June 30, 2015, the Trust issued a convertible debenture. The accounting policy adopted for the convertible debenture is as follows:

The components of compound instruments are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement. At the issue due, the fair value of the liability component is estimated using the prevailing market interest rate for a similar non-convertible instrument. This amount is recorded as a liability and thereafter accounted for using amortized cost until the instrument is converted or the

instrument matures. The liability component accretes up to the principal balance at maturity. The equity component is determined by deducting the liability component from the total fair value of the compound instrument and is recognized as equity, net of income tax effects, with no subsequent re-measurement. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts.

4. Note receivable

A promissory note of $40,000 arising from the exercise of options for Common Units between the Partnership and a company related through common directors was signed on June 29, 2011. The promissory note bears interest at 6% per annum, accruing daily and compounded and payable annually or as otherwise agreed by both parties; and is redeemable on demand. Interest income of $105 and $288 has been recorded in finance expense for the three and six months ended June 30, 2015 (three and six months ended June 30, 2014 - $Nil and $Nil). During the three and six months ended June 30, 2015, $4,500 and $9,000 (three and six months ended June 30, 2014 - $4,500 and $9,000) in principal repayments were received by the Trust.

5. Property and equipment

		Petroleum and Natural Gas Interests and Equipment
Cost		
Balance at December 31, 2014	$	32,425,326
Additions		887,277
Acquisitions (note 6)		3,772,753
Dispositions (note 6)		(50,847)
Changes in decommissioning costs (note 8)		(11,175)
Balance at June 30, 2015	$	37,023,334
Accumulated depletion		
Balance at December 31, 2014	$	5,918,882
Depletion for the period		738,079
Balance at June 30, 2015	$	6,656,961
Net book value:		
Balance at December 31, 2014	**$**	**26,506,444**
Balance at June 30, 2015	**$**	**30,366,373**

(a) Capitalized general and administrative and financing costs

The Trust has not capitalized any general and administrative expenses or interest in the six month periods ended June 30, 2015 or 2014.

(b) Impairment

Due to decreased commodity prices, there were indicators of impairment at June 30, 2015 and impairment tests were carried out at June 30, 2015 on each CGU. The recoverable amounts of each CGU were estimated at the fair value less costs of disposal based on discounted before tax future net cash flows of proved and probable reserves using forecast prices and costs estimated by the Trust's external reserve evaluators. The future net cash flows were discounted at a rate of 10% to 15% per annum. Property and equipment was not considered to be impaired at June 30, 2015 as a result of the tests performed.

6. Acquisitions

(i) Asset swaps

During the six months ended June 30, 2015, the Trust completed two asset swaps. The first asset swap was completed to acquire additional working interest in a property. The second swap was completed to acquire the working interest in a water disposal well and other assets which would allow for operational efficiencies. The property acquisitions were accounted for as a business combination under IFRS 3.

Net assets acquired:	
Petroleum and natural gas properties	$ 1,569,447
Decommissioning liabilities	(1,447,866)
Total net assets acquired, being the non-cash consideration	$ 121,581

The Trust recognized a gain on disposition of $70,734 as a result of the swaps. The net book value of the properties given up was $50,847.

(ii) Property acquisition

During the six months ended June 30, 2015, the Trust acquired additional working interests in petroleum and natural gas properties from one of its joint interest partners to create additional operating efficiencies. The property acquisition was accounted for as a business combination under IFRS 3.

Net assets acquired:	
Petroleum and natural gas properties	$ 2,203,306
Decommissioning liabilities	(1,429,668)
Net assets acquired	773,638
Gain on acquisition	(390,442)
Net assets acquired, net of gain on acquisition	$ 383,196

Consideration:	
Convertible debenture	$ 217,000
Extinguishment of financial liabilities (joint operation accounts payable)	166,196
Total non-cash consideration	$ 383,196

The revenue, operating results and net loss from the closing date of the business combination to June 30, 2015 as well as pro forma consolidated revenue, operating results and net loss giving effect to the acquisition as if it had occurred on January 1, 2015, are not practicable to determine. The acquired assets operations are not managed as a separate business unit or division of the Trust.

7. Exploration and evaluation assets

Balance at December 31, 2014 and June 30, 2015	$ 1,338,733

Intangible exploration and evaluation assets consist of the Trust's exploration projects for which proved and/or probable reserves have not yet been determined.

There were no significant indicators of impairment for the period ended June 30, 2015.

8. Decommissioning provision

The future decommissioning obligations were determined by management and were based on the Trust's net ownership interest, the estimated future costs to reclaim and abandon the wells, and the estimated timing of when the costs will be incurred.

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of the decommissioning provision associated with the retirement of petroleum and natural gas properties:

	June 30, 2015
Balance at December 31, 2014	**$ 6,063,703**
Liabilities acquired on acquisition (note 6)	**2,877,534**
Liabilities disposed	**(98,154)**
Change in estimated cash flows	**(529,460)**
Change in discount rate	**518,285**
Accretion (note 11)	**67,510**
Balance at June 30, 2015	**$ 8,899,418**

The total undiscounted amount of estimated cash flows required to settle the obligation as at June 30, 2015 was $11,111,000 (December 31, 2014 - $8,041,000) which has been discounted using a risk free rate of 1.68% at June 30, 2015 (2.30% at December 31, 2014). An inflation rate of between 2.0-2.2% has been used as at June 30, 2015. All of these obligations are estimated to be incurred in the years 2028 to 2029 and will be funded from general Trust resources at the time of the retirement.

A 1% increase in the risk free discount rate would result in a $1,098,000 decrease to decommissioning liabilities.

9. Debenture

On June 1, 2015, the Trust completed the issuance of a secured debenture in exchange for property and equipment with a fair value of $460,000. The debenture bears interest at 6% per annum, payable monthly commencing on June 1, 2016 and matures on June 1, 2022. The holder may elect to increase the outstanding principal obligations by the amount of the interest on the outstanding principal obligations due and payable to it in lieu of receiving payment of such interest amount.

10. Convertible debenture

On June 30, 2015, the Trust completed the issuance of a convertible secured debenture of $217,000 in exchange for certain assets (note 6(i)). The debenture bears interest at 6% per annum, payable monthly commencing on June 30, 2016, matures on June 30, 2022, and is convertible at the option of the holder into common units of the Trust at an amount equal to the market price of such units. If the market price is less than the minimum issue price of the exchange the units are listed on at the time of conversion, then the debenture is convertible at the minimum issue price.

The debenture has been classified as a financial liability, net of the fair value of the conversion feature at the date of issuance, which has been classified in unitholders' equity (deficiency). The debt portion will accrete up to the original face value of the debenture at maturity. The accretion and the interest paid are expensed on the consolidated statement of operations and comprehensive loss. The fair value of the conversion feature was determined on the date of issuance as the difference between the face value of the debenture and the discounted cash flows assuming a 10% effective interest rate, which was the estimated rate for debt with similar terms but without a conversion feature. When the debenture is converted to common units, the value of the conversion feature under unitholders' equity (deficiency) will be reclassified to common units.

The following table summarized changes in the convertible debentures:

	Liability Component	Equity Conversion Features	Total
Balance, December 31, 2014	$ -	$ -	$ -
Issuance of convertible debentures	193,815	23,185	217,000
Accretion of discount	285	-	285
Balance at June 30, 2015	$ 194,100	$ 23,185	$ 217,285

11. Preferred units

Authorized - Unlimited number of Preferred Units

Each preferred unit holder was entitled to one vote per unit but could only vote on matters related to the rights of the preferred unitholders. Such unitholders were entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees. If distributions in excess of $0.1025 per unit were declared in any year, the preferred unitholders would receive 10% of the excess distribution up to a maximum of $0.0175 per preferred unit. Subject to certain limitations, preferred unitholders were entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All preferred units were redeemable on demand by the unit holder or the Trust. If the redemption was demanded by the Trust the redemption amount was the original capital plus unpaid distributions. If the redemption was demanded by the unit holder the redemption price was determined as 90% of the market value of the unit. The market value was determined solely by the Administrator of the Trust. Redemptions were limited to $7,500 per month, and any redemptions requested in excess of that amount would be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust could also convert the preferred unit to a common unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units were considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units were bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative was the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument was measured at the redemption amount that is payable at the end of the year if the holder exercised its right to redeem the unit.

On June 21, 2015, the Trust converted all outstanding Preferred Units into Common Units. 33,797,206 Preferred Units were converted using a conversion ratio into 1,103,889,232 Common Units. The conversion ratio was determined according to a formula set out in the Declaration of Trust. The formula is primarily a function of the aggregate gross proceeds from the original issue by the Trust of all Preferred Units being converted and the deemed equity value of the Trust Units based on the consolidated net income of the Trust for and in respect of the two financial quarters preceding the date of conversion as adjusted in accordance with the Declaration of Trust.

The final quarterly distribution was paid to all outstanding preferred unitholders as at March 31, 2015. A distribution re-investment program ("DRIP") was initiated in September of 2011 to allow for the re-investment of distributions into Preferred Units. A total of $847,568 was paid out in distributions in the six months ended June 30, 2015 (six months ended June 30, 2014 - $1,654,472) with $306,212 (six months ended June 30, 2014 - $577,662) being re-invested in preferred shares.

During the six months ended June 30, 2015, the Trust redeemed 46,977 (six months ended June 30, 2014 – 50,000) Preferred Units at a price $1.00 per Preferred Unit. The redemption was accounted for as a reduction in the Preferred Units liability of $42,279 (six months ended June 30, 2014 - $45,000) and a reduction in the equity component of Preferred Units of $4,698 (six months ended June 30, 2014 - $5,000). The excess of the carrying value over the redemption price of $4,698 (six months ended June 30, 2014 - $5,000) was recorded as a component of finance expense.

	Number of Units	Total Amount	Equity Component	Liability Component
Issued and Outstanding Preferred Units				
Balance at December 31, 2014	33,537,971	$ 33,537,971	$ 3,353,797	$ 30,184,174
Redemption of shares	(46,977)	(46,977)	(4,698)	(42,279)
Issuance by way of DRIP	306,212	306,212	30,622	275,590
Conversion to Common Units	(33,797,206)	(33,797,206)	(3,379,721)	(30,417,485)
Balance at June 30, 2015	-	$ -	$ -	-

12. Common units

Authorized - Unlimited number of Common Units

Each unit holder is entitled to one vote per unit and shall be entitled to receive non-cumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust.

	Number of Units	**Total Amount**
Issued and Outstanding Common Units		
Balance at December 31, 2014	5,843,357	$ 3,571,402
Conversion of Preferred Units	1,103,888,605	33,797,206
Balance at June 30, 2015	1,109,731,962	$ 37,368,608

13. Finance expense

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	**2015**	2014
Distributions to Preferred Unitholders (note 11)	**$ 162**	$ 835,204	$ 847,730	$1,654,472
Accretion of decommissioning provision (note 8)	**33,122**	31,030	67,510	62,578
Excess of carrying value over redemption cost of Preferred Units (note 11)	**(4,645)**	7,148	(4,698)	7,148
Interest income	**(2,566)**	(9,470)	(8,846)	(21,873)
Accretion of convertible debenture (note 10)	**285**	-	285	-
Interest expense (notes 9 and 10)	**3,329**	-	3,329	-
	$ 29,687	$ 863,912	$ 905,310	$1,702,325

14. Supplemental cash flow information

Changes in non-cash working capital are comprised of:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	**2015**	2014
Cash provided by (used in):				
Accounts receivable	**$ (231,172)**	$ (13,180)	$ 130,640	$(844,889)
Prepaid expenses and deposits	**53,376**	64,538	72,596	65,475
Accounts payable and accrued liabilities	**(366,028)**	903,200	(282,769)	397,706
Plus: Change in Preferred Unit distributions payable	**541,881**	(45,156)	549,353	(34,088)
	$ (1,943)	909,402	$ 469,820	$(415,796)
Related to:				
Operating activities	**$ (242,565)**	$ (186,666)	$ 221,715	$(950,936)
Investing activities	**240,622**	1,096,068	248,105	535,140
Financing activities	**-**	-	-	-
Changes in non-cash working capital	**$ (1,943)**	$ 909,402	$ 469,820	$(415,796)

The following non-cash transactions were excluded from the consolidated statement of cash flows:

Re-invested distributions of $Nil and $306,212 during the three and six months ended June 30, 2015 (three and six months ended June 30, 2014 - $293,238 and $577,662) from the Trust's DRIP into Preferred Units (note 11).

Two asset swaps and one asset acquisition (note 6) which were non-monetary transactions.

The conversion of Preferred Units into Common Units (note 11).

The purchase of property and equipment in exchange for the issuance of debenture (note 9).

During the three and six months ended June 30, 2015, the Trust redeemed 46,452 and 46,977 (June 30, 2014 – 50,000 and 50,000) Preferred Units for $46,452 and $46,977 (June 30, 2014 - $50,000 and $50,000) of which $31,452 and $31,504 (June 30, 2014 - $42,500 and $39,477) remained in accounts payable at period end.

15. Financial risk management, financial instruments and capital management

(a) Overview

The Trust's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these condensed interim consolidated financial statements.

The Trust employs risk management strategies and polices to ensure that any exposure to risk is in compliance with the Trust's business objectives and risk tolerance levels. While the Board of Trustees has the overall responsibility for the establishment and oversight of the Trust's risk management framework, management has the responsibility to administer and monitor these risks.

(b) Credit risk

The Trust's maximum exposure to credit risk was:

	June 30, 2015	December 31, 2014
Cash	**$ 1,349,041**	$ 2,598,148
Accounts receivable	**552,595**	800,052
Note receivable	**13,078**	21,790
Maximum exposure to credit risk	**$ 1,914,714**	$ 3,419,990

Accounts receivable

The Trust has no allowance for doubtful accounts as at June 30, 2015 or December 31, 2014. During the three and six months ended June 30, 2015, the Trust recovered bad debts of $59,807 and $49,380, respectively (2014 – wrote-off receivables of $52,699 and $52,699, respectively) and the corresponding recovery (bad debt expense) is included in general and administrative expenses. The Trust considers all amounts greater than 90 days as past due.

The Trust's accounts receivable were comprised of the following amounts:

	June 30, 2015	December 31, 2014
Petroleum marketers	**$ 430,353**	$ 520,048
Joint operation partners	**17,103**	99,420
Water disposal customers	**27,823**	130,033
Other	**55,587**	40,238
Goods and Services Tax	**21,729**	10,313
Total accounts receivable	**$ 552,595**	$ 800,052

The accounts receivable is aged as follows:

	June 30, 2015	December 31, 2014
Current	**$ 521,862**	$ 687,573
Greater than 90 days	**30,733**	112,479
	$ 552,595	$ 800,052

The Trust considers all accounts receivable to be fully collectible and no allowance is required. Management follows up and takes necessary steps to ensure collection of all accounts receivable which are past due.

Cash

The Trust manages the credit exposure related to cash by selecting financial institutions with high credit ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(c) Liquidity risk

The Trust's accounts payable and accrued liabilities were comprised of the following amounts:

	June 30, 2015	December 31, 2014
Operating	**$ 854,435**	$ 659,106
Capital	**222,330**	602,049
Accruals	**29,000**	113,500
Other	**13,200**	272
Total accounts payable and accrued liabilities	**$ 1,118,965**	$ 1,374,927

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year.

The Trust is also subject to commitments as disclosed in note 17.

(d) Market risk

Market risks are as follows:

Commodity price risk

At June 30, 2015 and December 31, 2014, the Trust had no derivative financial contracts.

Foreign currency risk

At June 30, 2015 and December 31, 2014, the Trust had no forward exchange rate contracts nor any financial instruments denominated in foreign currencies.

Interest rate risk

At June 30, 2015 and December 31, 2014, The Trust had no interest rate swaps or financial contracts in place.

(e) Fair value of financial instruments

The fair values of note receivable, accounts receivable, deposits and accounts payable and accrued liabilities approximate their carrying values due to the relatively short-term nature of these instruments.

The convertible debenture bears interest at the fixed rate that the Trust would expect to pay for a similar financing transaction and, accordingly, the fair value approximates the carrying value.

The debenture bears interest at a fixed rate of 6%. A similar financing transaction would bear interest at a rate of 10%. Therefore, the fair value of the debenture would be approximately $411,500 at June 30, 2015.

(f) Capital management

The Trust's capital management objectives have not changed during the three months ended June 30, 2015.

The Trust monitors its working capital closely, which is determined on the following basis:

Balance sheet component	**June 30, 2015**	December 31, 2014
Cash	**$ 1,349,041**	$ 2,598,148
Accounts receivable	**552,595**	800,052
Note receivable	**13,078**	21,790
Prepaid expenses and deposits	**27,116**	99,712
Accounts payable and accrued liabilities	**(1,118,965)**	(1,374,927)
Current portion of preferred units	**-**	(1,572,195)
Working capital	**$ 822,865**	$ 572,580

The Trust is not subject to any externally imposed capital requirements other than the redemption feature of the Common Units (note 12).

16. Personnel expenses

The total remuneration for employee salaries included in general and administrative expenses during the three and six months ended June 30, 2015 was $27,801 and $71,491 (three and six months ended June 30, 2014 - $36,365 and $80,175).

17. Commitments

The Trust has entered into lease agreements for office space which expire in August 2015. The required lease payments, exclusive of operating costs, over the remaining term of the leases are as follows:

2015 - $4,395

18. Related party transactions

A director of the Trust controls or influences, by way of ownership, management and directorship, three oil and gas services companies that provide services to the Trust in the regular course of the Trust's business. Service fees in the amount of $92,800 and $220,900 in the three and six month period ended June 30, 2015 (three and six month period ended June 30, 2014 - $154,211 and $206,886) were incurred by the Trust to the related parties, all of which was charged to production and transportation expenses. At June 30, 2015, $Nil (December 31, 2014 - $1,052) related to these amounts was included in accounts payable and accrued liabilities and was due under normal credit terms.

Consulting fees of $111,705 and $155,395 was paid to executive officers and directors during the three and six months ended June 30, 2015 (three and six months ended June 30, 2014 - $Nil and $Nil).

19. Comparative figures

For the three and six months ended June 30, 2014, $40,558 and $80,177 have been reclassified from water disposal revenue to production and transportation expense to conform with the current period's presentation.

Petrocapita Income Trust

Consolidated Financial Statements

December 31, 2014

Management's Report

Management has prepared the consolidated financial statements of Petrocapita Income Trust in accordance with International Financial Reporting Standards ("IFRS").

Management is responsible for the integrity and objectivity of the financial information. Where necessary, the consolidated financial statements include estimates that are based on management's informed judgments. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized, and reliable accounting records are produced for financial purposes.

Collins Barrow Calgary LLP, an independent firm of Chartered Accountants, was appointed by the Trust's unitholders to conduct an audit of the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Trustees is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board meets regularly with management and has met with the independent auditors to ensure that managements' responsibilities are properly discharged, to review the consolidated financial statements and has approved the consolidated financial statements.

Stephen Johnston
Managing Director

March 19, 2015

Collins Barrow
Chartered Accountants & Consultants

Collins Barrow Calgary LLP
1400 First Alberta Place
777 – 8th Avenue S.W.
Calgary, Alberta, Canada
T2P 3R5

T. 403.298.1500
F. 403.298.5814
e-mail: calgary@collinsbarrow.com

Independent Auditors' Report

To the Trustees of
Petrocapita Income Trust

We have audited the accompanying consolidated financial statements of Petrocapita Income Trust and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2014, and the consolidated statement of operations and comprehensive loss, consolidated statement of changes in unitholders' equity (deficiency) and consolidated statement of cash flows for the year then ended, and 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.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' 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 is sufficient and appropriate to provide a basis for our

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Petrocapita Income Trust and its subsidiaries as at December 31, 2014, and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards.

Collins Barrow Calgary LLP

CHARTERED ACCOUNTANTS

Calgary, Canada
March 19, 2015

Petrocapita Income Trust
Consolidated Balance Sheet
December 31, 2014
(in Canadian dollars)

	Notes	2014	2013
Assets			
Current assets			
Cash		$ 2,598,148	$ 4,569,186
Accounts receivable	13(b)	800,052	749,503
Note receivable	4	21,790	36,133
Prepaid expenses and deposits		99,712	85,564
		3,519,702	5,440,386
Non-current assets			
Property and equipment	6	26,506,444	25,595,315
Exploration and evaluation assets	7	1,338,733	1,952,687
		$ 31,364,879	$ 32,988,388
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	13(c)	$ 1,374,927	$ 1,692,033
Current portion of preferred units	9	1,572,195	-
		2,947,122	1,692,033
Non-current liabilities			
Decommissioning provision	8	6,063,703	4,555,788
Preferred Units	9	28,611,979	29,173,907
		37,622,804	35,421,728
Unitholders' Deficiency			
Common Units	10	3,571,402	3,571,402
Equity component of Preferred Units	9	3,353,797	3,241,545
Deficit		(13,183,124)	(9,246,287)
		(6,257,925)	(2,433,340)
		$ 31,364,879	$ 32,988,388

Commitments (note 15)
See accompanying notes to the consolidated financial statements.

Approved by the Trustees

(signed) "Stephen Johnston", Trustee

(signed) "David Forrest", Trustee

Petrocapita Income Trust
Consolidated Statement of Operations and Comprehensive Loss
Year Ended December 31, 2014
(in Canadian dollars)

	Notes	2014	2013
Revenue			
Petroleum revenue		$ 10,009,414	$ 8,760,866
Water disposal revenue	16	521,005	48,923
Royalties		(1,725,557)	(1,275,246)
		8,804,862	7,534,543
Expenses			
Production and transportation		5,829,424	5,089,668
General and administrative		721,266	706,495
Depletion	6	2,293,454	2,343,101
		8,844,144	8,139,264
Operating loss		(39,282)	(604,721)
Finance expense, net	11	(3,440,488)	(3,174,036)
Gain on sale of exploration and evaluation assets	7	157,933	65,000
Loss on impairment of exploration and evaluation assets	7	(615,000)	-
Net loss and comprehensive loss		(3,936,837)	(3,713,757)
Loss and comprehensive loss attributable to common unitholders		$ (3,936,837)	$ (3,713,757)

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Changes in Unitholders' Equity (Deficiency)
For the Year Ended December 31, 2014
(in Canadian dollars)

	Notes	Number of Common Units	Common Units Stated Value	Equity Component of Preferred Units	Deficit	Total Unitholders' Equity (Deficiency)
Balance at December 31, 2012		5,843,357	$ 3,571,402	$ 3,143,367	$ (5,532,530)	$ 1,182,239
Issuance of Preferred Units	9	-	-	109,078	-	109,078
Redemption of Preferred Units	9	-	-	(10,900)	-	(10,900)
Loss and comprehensive loss for the year		-	-	-	(3,713,757)	(3,713,757)
Balance at December 31, 2013		5,843,357	3,571,402	3,241,545	(9,246,287)	(2,433,340)
Issuance of Preferred Units	9	-	-	119,081	-	119,081
Redemption of Preferred Units	9	-	-	(6,829)	-	(6,829)
Loss and comprehensive loss for the year		-	-	-	(3,936,837)	(3,936,837)
Balance at December 31, 2014		5,843,357	$ 3,571,402	$ 3,353,797	$ (13,183,124)	$ (6,257,925)

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Cash Flows
For the Year Ended December 31, 2014
(in Canadian dollars)

	Notes	2014	2013
Cash provided by (used in):			
Cash flows from operating activities			
Loss for the year		$ (3,936,837)	$ (3,713,757)
Adjustments for:			
Depletion	6	2,293,454	2,343,101
Distribution to Preferred Unitholders	11	3,363,738	3,258,189
Accretion	11	126,195	23,307
Interest on note receivable	4	(3,657)	-
Preferred Unit redemption	9	(6,829)	(10,900)
Gain on sale of exploration and evaluation assets	7	(157,933)	(65,000)
Loss on impairment of exploration and evaluation assets		615,000	-
Changes in non-cash working capital	12	(301,564)	301,581
Net cash provided by operating activities		1,991,567	2,136,521
Cash flows used in investing activities			
Additions to exploration and evaluation assets	7	(76,503)	(46,111)
Acquisition of oil and natural gas interests	5	-	(8,282,263)
Additions to property and equipment	6	(1,747,406)	(2,362,581)
Proceeds from disposition of exploration and evaluation assets	7	157,933	65,000
Changes in non-cash working capital	12	(83,680)	733,809
Net cash used in investing activities		(1,749,656)	(9,892,146)
Cash flows from financing activities			
Redemption of Preferred Units	9	(61,465)	(98,100)
Preferred Unit distributions paid	9	(2,169,484)	(2,167,404)
Repayments of note receivable	4	18,000	7,500
Net cash provided by financing activities		(2,212,949)	(2,258,004)
Change in cash		(1,971,038)	(10,013,629)
Cash, beginning of year		4,569,186	14,582,815
Cash, end of year		$ 2,598,148	$ 4,569,186

See accompanying notes to the consolidated financial statements.

1. General business description

Petrocapita Income Trust (the "Trust") was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a diversified portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "Partnership"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

The Partnership is managed by the General Partner, Petrocapita GP I Ltd.

The address and principal place of business of the Trust is 803, 5920 Macleod Trail SW, Calgary, Alberta, T2H 0K2.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the Income Tax Act (Canada), the Trust is subject to income taxes only on income that is not distributed or distributable to the unitholders. The Trust, to date, has no undistributed income. As a limited partnership, the income tax consequences of the Limited Partnership and ultimately those of the Trust are deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability is reflected in the consolidated financial statements.

2. Basis of preparation

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the International Financial Reporting Interpretations Committee (IFRIC).

(b) Reporting entity

The consolidated financial statements of the Trust as at and for the year ended December 31, 2014 comprise the Trust and its two subsidiaries, the Partnership and the General Partner, Petrocapita GP 1 Ltd.

(c) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following:

(i) Derivative financial instruments are measured at fair value; and

(ii) Financial instruments designated as "fair value through income (loss)".

The methods used to measure fair values are discussed in note 13.

(d) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Trust's functional currency.

(e) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to estimation uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

Significant estimates made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production volumes, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Trust's oil and natural gas properties and equipment, the calculation of depletion and depreciation and the provision for decommissioning liabilities due to changes in expected future cash flows. The Trust's oil and natural gas reserves are assessed at least annually by independent reserve engineers.

Amounts recorded for the decommissioning provision and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates.

The allocation of proceeds on the issuance of preferred units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the preferred units.

The valuation of accounts receivable is based on management's best estimate of collectability and the provision for doubtful accounts.

Significant judgments made by management in the preparation of these consolidated financial statements are as follows:

The Trust's exploration and evaluation assets and property and equipment are aggregated into cash-generating units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Trust's operations. The Trust has identified Alberta and Saskatchewan as its core CGUs.

Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of oil and natural gas reserves, production rates, future oil and natural gas prices, future costs, discount rates and other relevant assumptions.

The decision to transfer exploration and evaluation assets to property and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and/or probable reserves as well as the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future petroleum and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to the years presented in these consolidated financial statements:

(a) Basis of consolidation:

(i) Subsidiaries

Subsidiaries are entities controlled by the Trust. Control exists when the Trust has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The Trust owns all but 10 of the Partnership's limited partnership units with the other 10 held by the General Partner. The Trust owns 100% of the General Partner and the General Partner cannot be removed except under very limited and specific circumstances. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

(ii) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Jointly controlled assets and jointly controlled operations

Certain assets of the Trust's petroleum and natural gas activities consist of jointly controlled assets. The consolidated financial statements include the Trust's proportionate share of these jointly controlled assets and the relevant revenue and related costs.

(c) Business combinations

Business combinations are accounted for using the acquisition method where the acquisition of companies and assets meet the definition of an asset under IFRS. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Following initial recognition, goodwill is recognized at cost less any accumulated impairment losses. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded in earnings as a gain. Associated transaction costs are expensed when incurred.

(d) Exploration and evaluation assets and property and equipment

(i) Exploration and evaluation assets

Pre-license expenditures incurred before the Trust has obtained legal rights to explore an area are expensed.

Exploration and evaluation costs include the costs of acquiring licenses, exploratory drilling, geological and geophysical activities, acquisition of mineral and surface rights and technical studies. Exploration and evaluation costs are capitalized as exploration and evaluation assets when the technical feasibility and commercial viability of extracting petroleum and natural gas reserves have yet to be determined. Exploration and evaluation assets are measured at cost and are not depleted or depreciated. Exploration and evaluation assets, net of any impairment loss, are transferred to property and equipment when proved and/or probable reserves are determined to exist. If an area is determined not to be technically feasible and commercially viable, or the Trust discontinues its exploration and evaluation activities, the unrecoverable costs are expensed.

Exchanges, farm-outs or swaps that involve only exploration and evaluation assets are accounted for at cost. Any gains or losses from the divestiture of exploration and evaluation assets are recognized in the consolidated statement of operations and comprehensive loss.

(ii) Property and equipment

All costs directly associated with the development and production of petroleum and natural gas interests are capitalized on an area-by-area basis as petroleum and natural gas interests if they extend or enhance the recoverable reserves of the underlying assets and are measured at cost less accumulated depletion and depreciation and net impairment losses. These costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include property acquisitions with proved and/or probable reserves, development drilling, completion, gathering and infrastructure, decommissioning costs and transfers of exploration and evaluation assets.

The costs of routine maintenance and the day-to-day servicing of property and equipment are recognized in income as incurred.

Exchanges or swaps of property and equipment are measured at fair value unless the transaction lacks commercial substance or neither the fair value of the asset received nor the asset given up can be reliably estimated. When fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gains or losses from the divestiture of property and equipment are recognized in income (loss).

(iii) Depletion and depreciation

Petroleum and natural gas interests included in property and equipment are depleted on an area-by-area basis using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs. Petroleum and natural gas interests, including processing facilities and well equipment, are componentized into groups of assets with similar useful lives for purposes of performing depletion calculations. Production and reserves of natural gas are converted to equivalent barrels of crude oil on the basis of six thousand cubic feet of natural gas to one barrel of oil. Changes in estimates used in prior periods that affect the unit-of-production calculations, such as proved and probable reserves, do not give rise to prior period adjustments and are dealt with on a prospective basis.

(e) Impairment of non-financial assets

The carrying amounts of the Trust's non-financial assets, other than exploration and evaluation assets are reviewed for indicators of impairment at each reporting date. If indicators of impairment exist, the recoverable amount of the asset is estimated. Exploration and evaluation assets are assessed separately for impairment when they are reclassified to property and equipment and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purposes of assessing impairment, exploration and evaluation assets and property and equipment are tested separately and are grouped into CGUs, defined as the lowest levels for which there are separately identifiable independent cash inflows. If, at any time, it is determined that the Trust has no future exploration plans and commercial production cannot be achieved in relation to an area, the associated costs are written down to the estimated recoverable amount, or fully de-recognized and the amount of the write-down is expensed in the consolidated statement of operations and comprehensive loss.

The recoverable amount of a CGU is the greater of its fair value less costs of disposal and its value in use. Fair value is determined to be the amount for which the asset could be sold in an arm's length transaction between knowledgeable and willing parties. Fair value less costs of disposal may be determined based on discounted future net cash flows of proved and probable reserves using forecast prices and costs and including future development costs. These cash flows are discounted at an appropriate discount rate which would be applied by a market participant. Value in use is determined by estimating the present value of the future net cash flows to be derived from the continued used of the cash-generating unit in its present form. These cash flows are discounted at a rate based on the time value of money and risks specific to the CGU.

The fair value less costs of disposal used to determine the recoverable amounts of property and equipment and exploration and evaluation assets are classified as Level 3 fair value measurements as they are not based on observable market data.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the consolidated statement of operations and comprehensive loss.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Provisions and contingent liabilities

Provisions are recognized by the Trust when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of that obligation. Provisions are stated at the present value of the expenditure expected to settle the obligation. The obligation is not recorded and is disclosed as a contingent liability if it is not probable that an outflow will be required, if the amount cannot be estimated reliably or if the existence of the outflow can only be confirmed by the occurrence of a future event.

Decommissioning provision

An obligation to incur restoration, rehabilitation and environmental costs arises when environmental disturbance is caused by the exploration, development or ongoing production of petroleum and natural gas properties.

A decommissioning provision is recognized as a liability for obligations associated with the abandonment of petroleum and natural gas wells, removal of equipment from leased acreage and returning such land to its original condition as set by standards of environmental regulations.

The Trust records the fair value of each decommissioning obligation in the year a well or related asset is drilled, constructed or acquired. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate. The expected future cash flows reflect current market assessments and the risks specific to the liability.

The obligation is reviewed regularly by the Trust's management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related property and equipment or exploration and evaluation assets, and a corresponding liability is recognized. The increase in petroleum and natural gas interests is depleted on the same basis as the related petroleum and natural gas component, while the liability is accreted to income until it is settled or sold. Subsequent to the initial measurement, the obligation is adjusted at the end of each year to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the pre-tax risk-free rate. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or changes in the risk free rate are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision to the extent the provision was established.

(g) Revenue

Revenue from the sale of petroleum and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

Revenue from the disposal of water is recognized based on volumes disposed of for customers.

Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered or disposed of and contractual delivery points.

The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same year in which the related revenue is earned and recorded.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(h) Finance income and expenses

Finance income, consisting of interest income, is recognized as it accrues in the consolidated statement of operations and comprehensive loss, using the effective interest rate method.

Finance expense comprises accretion of the discount on decommissioning provision, the excess of carrying value over redemption costs on Preferred Units, distributions paid to Preferred Unitholders, and impairment losses recognized on financial assets.

(i) Financial instruments

(i) *Classification and measurement*

Financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as “fair value through profit or loss”, “loans and receivables”, “available-for-sale”, “held-to-maturity”, or “financial liabilities measured at amortized cost” as defined by International Accounting Standards (IAS) 39, *“Financial Instruments: Recognition and Measurement”.*

The Trust has designated cash as “held for trading” which is measured at fair value through profit or loss.

The Trust has designated accounts receivable, note receivable and deposits as “loans and receivables”, accounts payable and accrued liabilities as “financial liabilities measured at amortized cost” and the liability component of preferred units as "fair value through profit or loss".

(ii) *Derivative financial instruments*

The Trust may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. The Trust's policy is not to utilize derivative financial instruments for speculative purposes. All financial derivative contracts are classified as “fair value through profit or loss”.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related. Changes in the fair value of separable embedded derivatives are recognized immediately in the consolidated statement of operations and comprehensive loss. The Preferred Units have an embedded derivative related to the redemption feature of the units at fair value (note 9).

(iii) *Equity instruments*

Common Units are classified as equity. Incremental costs directly attributable to the issue of units are recognized as a deduction from equity.

Preferred Units are considered to be a hybrid liability and equity instrument with the liability component measured based on the unitholders redemption feature. Upon initial issuance the units are bifurcated into the liability and equity components.

(iv) *Impairment*

The Trust assesses at each balance sheet date whether there is objective evidence that financial assets, other than those designated as "fair value through income (loss)" are impaired. When impairment has occurred, the cumulative loss is recognized in the consolidated statement of operations and comprehensive loss. For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the financial asset's original effective interest rate. Impairment losses may be reversed in subsequent periods.

(j) Recent accounting pronouncements

Changes in accounting policies

On January 1, 2014, the Trust adopted the following new standards and amendments which became effective for years beginning on or after January 1, 2014:

IAS 32, Financial Instruments: Presentation, has been amended to clarify certain requirements for offsetting financial assets and liabilities. The amendment addresses the meaning and application of the concepts of legally enforceable right of set-off and simultaneous realization and settlement. This amendment had no impact on the Trust's results or financial position.

IAS 36, Impairment of Assets, has been amended to require disclosure of the recoverable amount of an asset (including goodwill) or a cash generating unit when an impairment loss has been recognized or reversed in the period. When the recoverable amount is based on fair value less costs of disposal, the valuation techniques and key assumptions must also be disclosed. The amendment has been reflected in all notes where an impairment loss has been recognized.

IFRIC 21, Levies, on the accounting for levies imposed by governments clarifies the obligating event that gives rise to a liability to pay a levy. IFRIC 21 is effective for annual periods beginning on or after January 1, 2014. The adoption of this IFRIC had no impact on the Trust's results or financial position.

The following pronouncements will become effective for fiscal periods subsequent to December 31, 2014:

IFRS 15, Revenue from Contracts with Customers provides a comprehensive new standard on revenue recognition. It specifies how and when to recognize revenue as well as requiring entities to provide more informative and relevant disclosure. The new standard is effective for years beginning on or after January 1, 2017. IFRS 15 is being assessed to determine its impact on the Trust's results and financial position.

IFRS 9, Financial Instruments, addresses the classification and measurement of financial assets. IFRS 9 replaces the guidance on 'classification and measurement' of financial instruments in IAS 39, Financial Instruments - Recognition and Measurement. The new standard requires a consistent approach to the classification of financial assets and replaces the numerous categories of financial assets in IAS 39 with two categories, measured at either amortized cost or at fair value. For financial liabilities, the standard retains most of the IAS 39 requirements, but where the fair value option is taken, the part of a fair value change due to an entity's own credit risk is recorded in other comprehensive income rather than the consolidated statement of operations and comprehensive loss, unless this creates an accounting mismatch. It also includes a new general hedge accounting model. IFRS 9 is effective for fiscal periods beginning on or after January 1, 2018. IFRS 9 is being assessed to determine its impact on the Trust's results and financial position.

4. Note receivable

A promissory note of $40,000 arising from the exercise of options for Common Units between the Partnership as the lender and a company related through common directors was signed on June 29, 2011. The promissory note bears interest at 6% per annum, accruing daily and compounded and payable annually or as otherwise agreed by both parties; and is redeemable on demand. Total interest of $3,657 has been recorded in finance expense for the year ended December 31, 2014 (2013 - $Nil). During the year ended December 31, 2014, $18,000 (2013 - $7,500) in principal repayments were received by the Trust.

5. Asset Acquisitions

During the year ended December 31, 2013, the Trust completed acquisitions of certain conventional producing oil and natural gas assets for $8,282,263 after closing adjustments. The purchases were recognized as business combinations in accordance with IFRS 3 – Business Combinations, as the acquired assets and liabilities assumed constituted a business. The assets acquired are a strategic fit with the Trust's existing asset portfolio because the Trust increased their production in existing areas which increased operational efficiencies and diversified the Trust's product mix. The fair value of the cash consideration given approximates the fair value of the net assets acquired.

The purchase prices were allocated to the net assets acquired as follows:

Oil and natural gas interests (note 6)	$ 10,547,963
Decommissioning provisions (note 8)	(2,265,700)
Total net assets acquired and cash consideration	$ 8,282,263

These consolidated financial statements incorporate the results of operations of the acquired properties from their closing dates, being March 22, 2013 and April 22, 2013, respectively, onwards. The revenue, operating results and net earnings (loss) attributable to the acquisitions from the respective closing dates to December 31, 2013, as well as the pro forma consolidated revenue, operating results and net earnings (loss) giving effect to the acquisitions as if they had occurred on January 1, 2013, are not practicable to determine. The operations attributable to the acquisitions are not managed as separate business units of divisions of the Trust.

6. Property and equipment

		Petroleum and Natural Gas Interests and Equipment
Cost		
Balance at December 31, 2012	$	14,946,991
Additions		2,362,581
Acquisition of oil and natural gas interests (note 5)		10,547,963
Changes in decommissioning costs (note 8)		1,363,208
Balance at December 31, 2013		29,220,743
Additions		1,747,406
Transfer from exploration and evaluation assets (note 7)		75,457
Changes in decommissioning costs (note 8)		1,381,720
Balance at December 31, 2014	$	32,425,326
Accumulated depletion		
Balance at December 31, 2012	$	1,282,327
Depletion for the year		2,343,101
Balance at December 31, 2013		3,625,428
Depletion for the year		2,293,454
Balance at December 31, 2014	$	5,918,882
Net book value		
Balance at December 31, 2013	**$**	**25,595,315**
Balance at December 31, 2014	**$**	**26,506,444**

(a) Capitalized general and administrative and financing costs

The Trust has not capitalized any general and administrative expenses or interest in the years ended December 31, 2014 or 2013.

(b) Impairment

Impairment tests were carried out at December 31, 2014 and 2013 on each CGU. The recoverable amounts of each CGU were estimated at the fair value less costs of disposal based on discounted before tax future net cash flows of proved and probable reserves using forecast prices and costs estimated by the Trust's external reserve evaluators. The future net cash flows were discounted at a rate of 10% to 15% per annum in 2014 (2013 – 10% to 15%). Property and equipment was not considered to be impaired at December 31, 2014 or 2013.

7. Exploration and evaluation assets

Balance at December 31, 2012	$ 1,906,576
Additions	46,111
Balance at December 31, 2013	$ 1,952,687
Additions	76,503
Transfer to property and equipment (note 6)	(75,457)
Impairment	(615,000)
Balance at December 31, 2014	$ 1,338,733

Intangible exploration and evaluation assets consist of the Trust's exploration projects for which proved and/or probable reserves have not yet been determined.

Impairment loss

An impairment loss of $615,000 (2013 - $Nil) was recognized for the year ended December 31, 2014, related to the Trust's Saskatchewan CGU based on management's assessment of fair value based on current market rates for undeveloped land sales. At December 31, 2014, $1,070,000 of Saskatchewan land is expected to be recoverable.

During the year ended December 31, 2014, the Trust disposed of exploration and evaluation assets with a carrying value of $Nil (2013 - $Nil) for proceeds of $157,933 (2013 - $65,000). Accordingly, a gain has been recognized in the consolidated statement of operations.

8. Decommissioning provision

The future decommissioning obligations were determined by management and were based on the Trust's net ownership interest, the estimated future costs to reclaim and abandon the wells, and the estimated timing of when the costs will be incurred.

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of the decommissioning provision associated with the retirement of petroleum and natural gas properties:

	2014	2013
Balance, beginning of year	**$ 4,555,788**	$ 903,573
Liabilities acquired (note 5)	**-**	2,265,700
Additions (note 6)	**54,605**	523,960
Change in estimated cash flows (note 6)	**1,327,115**	839,248
Accretion (note 11)	**126,195**	23,307
Balance, end of year	**$ 6,063,703**	$ 4,555,788

The total undiscounted amount of estimated cash flows required to settle the obligation as at December 31, 2014 was $8,041,000 (2013 - $5,515,914) which has been discounted using a risk free rate of 2.30% at December 31, 2014 (2.77% at December 31, 2013). An inflation rate of 2% has been used throughout. All of these obligations are estimated to be incurred in the years 2026 to 2028 and will be funded from general Trust resources at the time of the retirement.

9. Preferred units

Authorized - Unlimited number of Preferred Units

Each preferred unit holder is entitled to one vote per unit but may only vote on matters related to the rights of the preferred unitholders. Such unitholders shall be entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees. If distributions in excess of $0.1025 per unit are declared in any year, the preferred unitholders will receive 10% of the excess distribution up to a maximum of $0.0175 per preferred unit. Subject to certain limitations, preferred unitholders are entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All preferred units are redeemable on demand by the unit holder or the Trust. If the redemption is demanded by the Trust the redemption amount is the original capital plus unpaid distributions. If the redemption is demanded by the unit holder the redemption price is determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust may also convert the preferred unit to a common unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units are considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units are bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative is the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument is measured at the redemption amount that is payable at the end of the year if the holder exercised its right to redeem the unit.

Quarterly distributions were paid to all outstanding preferred unitholders as at March 31, 2014, June 30, 2014, September 30, 2014 and December 31, 2014. A distribution re-investment program ("DRIP") was initiated in September of 2011 and the first re-investment of distributions took place on September 30, 2011. A total of $3,363,738 was paid out in distributions in 2014 (2013 - $3,258,189) with $1,190,813 (2013 - $1,090,785) being re-invested in preferred shares.

During the year ended December 31, 2014, the Trust redeemed 68,294 (2013 - 109,000) Preferred Units at a price $0.90 (2013 - $0.90) per preferred unit. The redemption was accounted for as a reduction in the Preferred Units liability of $61,465 (2013 - $98,100) and a reduction in the equity component of Preferred Units of $6,829 (2013 - $10,900). The excess of the carrying value over the redemption price of $6,829 (2013 - $10,900) was recorded as a component of finance expenses.

	Number of units	Total Amount	Equity Component	Liability Component
Issued and Outstanding Preferred Units				
Balance at December 31, 2012	31,433,667	$ 31,433,667	$ 3,143,367	$ 28,290,300
Redemption of shares	(109,000)	(109,000)	(10,900)	(98,100)
Issuance by way of DRIP	1,090,785	1,090,785	109,078	981,707
Balance at December 31, 2013	32,415,452	32,415,452	3,241,545	29,173,907
Redemption of shares	(68,294)	(68,294)	(6,829)	(61,465)
Issuance by way of DRIP	1,190,813	1,190,813	119,081	1,071,732
Balance at December 31, 2014	33,537,971	$ 33,537,971	$ 3,353,797	30,184,174
Less current portion				(1,572,195)
Long-term portion				$ 28,611,979

10. Common units

Authorized - Unlimited number of Common Units

Each unit holder is entitled to one vote per unit and shall be entitled to receive non-cumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust.

11. Finance (income) expenses

	2014	2013
Distributions to Preferred Unitholders (note 9)	**$ 3,363,738**	$ 3,258,189
Accretion of decommissioning provision (note 8)	**126,195**	23,307
Excess of carrying value over redemption cost of Preferred Units (note 9)	**(6,829)**	(10,900)
Interest income	**(42,616)**	(96,560)
	$ 3,440,488	$ 3,174,036

12. Supplemental cash flow information

Changes in non-cash working capital are comprised of:

	2014	2013
Cash provided by (used in):		
Accounts receivable	**$ (50,549)**	$ (504,610)
Prepaid expenses and deposits	**(14,148)**	745,371
Accounts payable and accrued liabilities	**(317,106)**	794,629
Less: Change in Preferred Unit distributions payable	**(3,441)**	-
	$ (385,244)	$ 1,035,390
Related to:		
Operating activities	**$ (301,564)**	$ 301,581
Investing activities	**(83,680)**	733,809
Financing activities	**-**	-
Changes in non-cash working capital	**$ (385,244)**	$ 1,035,390

The following non-cash transaction was excluded from the consolidated statement of cash flows:

Re-invested distributions of $1,190,813 during the year ended December 31, 2014 (2013 - $1,090,785) from the Trust's DRIP into preferred units (note 9).

13. Financial risk management, financial instruments and capital management

(a) Overview

The Trust's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Trust employs risk management strategies and polices to ensure that any exposure to risk is in compliance with the Trust's business objectives and risk tolerance levels. While the Board of Trustees has the overall responsibility for the establishment and oversight of the Trust's risk management framework, management has the responsibility to administer and monitor these risks.

(b) Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The majority of the Trust's accounts receivable are due from petroleum and marketers and are subject to normal industry credit risk.

The Trust's maximum exposure to credit risk was:

	2014	2013
Cash	**$ 2,598,148**	$ 4,569,186
Note receivable	**21,790**	36,133
Accounts receivable	**800,052**	749,503
Maximum exposure to credit risk	**$ 3,419,990**	$ 5,354,822

Accounts receivable

All of the Trust's operations are conducted in Canada. The Trust's exposure to credit risk is influenced mainly by the individual characteristics of each customer. Significant changes in industry conditions and risks that negatively impact customers' ability to generate cash flow will increase the risk of not collecting receivables. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit.

The Trust markets its petroleum primarily to two petroleum marketers. Due to the small size of the Trust, it is efficient to market all of its petroleum to two marketers. The receivables from joint interest partners and from water disposal are generally with petroleum producers. Management monitors the credit rating with its marketers, joint interest partners and water disposal customers to ensure no collection issues arise. Receivables from petroleum marketers joint interest partners and water disposal customers are normally collected on the 25th day of the month following production.

The Trust had no allowance for doubtful accounts as at December 31, 2014 or 2013. During the year ended December 31, 2014, the Trust wrote-off receivables of $302,306 (2013 - $Nil) net of payables of $201,828 (2013 - $Nil) from the same parties, for net bad debts of $100,478 (2013 - $Nil), which have been included in general and administrative expenses based on specific accounts that are not believed to be collectible. When determining whether past due accounts are collectible, the Trust

factors in the past credit history of the counterparties. The Trust considers all amounts greater than 90 days as past due.

The Trust's accounts receivable were comprised of the following amounts:

	2014	2013
Petroleum marketers	**$ 520,048**	$ 650,413
Joint interest partners	**99,420**	56,818
Water disposal customers	**130,033**	10,499
Other	**50,551**	31,773
Total accounts receivable	**$ 800,052**	$ 749,503

The accounts receivable is aged as follows:

	2014	2013
Current	**$ 687,573**	$ 749,503
Greater than 90 days	**112,479**	-
	$ 800,052	$ 749,503

The majority of accounts receivable aged greater than 90 days have been collected subsequent to December 31, 2014. Management follows up and takes necessary steps to ensure collection of all accounts receivable which are past due.

Cash

The Trust manages the credit exposure related to cash by selecting financial institutions with high credit ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(c) Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust's approach to managing liquidity is to ensure it will have sufficient liquidity to meet its liabilities when due. The Trust's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations.

The Trust's financial liabilities consist of accounts payable and accrued liabilities and preferred units. Accounts payable consists of invoices payable to trade suppliers for operating (e.g., general, administrative, royalty, production and transportation), capital (e.g., drilling, completion and equipping of oil wells) and financing (commissions and other costs for the issue of preferred units) expenditures and are paid within one year. The preferred units are redeemable at the option of the holder and accrue cumulative distributions at $0.1025 per unit per year.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Trust prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures. Refer to note 13(f) for further disclosure on the management of capital.

The Trust's accounts payable and accrued liabilities are aged as follows:

	2014	2013
0 - 30 days	**$ 1,194,647**	$ 1,692,032
31 to 60 days	**135,191**	-
61 to 90 days	**28,315**	-
Greater than 90 days	**16,774**	-
Total accounts payable and accrued liabilities	**$ 1,374,927**	$ 1,692,032

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year. The Trust expects to only redeem the Preferred Units if demanded by the holder in accordance with the terms of the units.

(d) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the years ended December 31, 2014 and 2013 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Foreign currency risk

Prices for petroleum are determined in global markets and generally denominated in United States dollars. The Trust had no forward exchange rate contracts in place nor any working capital items denominated in foreign currencies as at or during the years ended December 31, 2014 and 2013. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of petroleum and natural gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of petroleum and natural gas commodities. The impact of such exchange rate fluctuations on the Trust's net income (loss) cannot be accurately quantified.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust has no interest bearing debt at December 31, 2014 or 2013 and the preferred unit distributions are at a fixed amount per unit. Consequently the Trust is not directly exposed to material interest rate risk. However, inherently, changes in interest rates may affect the general economy. The Trust had no interest rate swaps or financial contracts in place as at or during the years ended December 31, 2014 or 2013.

(e) Fair value of financial instruments

The fair values of note receivable, accounts receivable, deposits and accounts payable and accrued liabilities approximate their carrying values due to the relatively short-term nature of these instruments.

The significance of inputs used in making fair value measurements are examined and classified according to a fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly, and are based on valuation models and techniques where the inputs are derived from quoted indices. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

Cash is measured at fair value based on Level 1 inputs, the liability component of the preferred units is measured at fair value based on Level 2 inputs.

(f) Capital management

The Trust's capital is defined to be unitholders' equity and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments.

The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis:

Balance sheet component	**2014**	2013
Cash	**$ 2,598,148**	$ 4,569,186
Accounts receivable	**800,052**	749,503
Note receivable	**21,790**	36,133
Prepaid expenses and deposits	**99,712**	85,564
Accounts payable and accrued liabilities	**(1,374,927)**	(1,692,033)
Current portion of preferred units	**(1,572,195)**	-
Working capital	**$ 572,580**	$ 3,748,353

The Trust is not subject to any externally imposed capital requirements other than the redemption feature of the Preferred and Common Units (notes 9 and 10).

The Trust's capital management objectives have not changed during the years ended December 31, 2014 or 2013.

14. Personnel expenses

The total remuneration for employees included in general and administrative expenses during the year ended December 31, 2014 was $155,333 (2013 - $177,958). No remuneration was paid to executive officers and directors.

15. Commitments

The Trust has entered into lease agreements for office space which expire in June and September 2015. The required lease payments, exclusive of operating costs, over the remaining term of the leases are as follows:

2015 - $31,965

16. Related party transactions

A director of the Trust controls or influences, by way of ownership, management and directorship, three oil and gas services companies that provide services to the Trust in the regular course of the Trust's business. Service fees in the amount of $444,690 in the year ended December 31, 2014 (year ended December 31, 2013 - $406,497) were incurred by the Trust to the related parties, all of which was charged to production and transportation expenses. At December 31, 2014, $1,052 (December 31, 2013 - $19,378) related to these amounts was included in accounts payable and accrued liabilities and was due under normal credit terms.

17. Comparative figures

Certain comparative figures have been reclassified to conform with the current year's presentation. Management has determined that the Trust's water disposal revenue should be separated from petroleum revenue for greater clarity.

Petrocapita Income Trust

Consolidated Financial Statements

December 31, 2013

Management's Report

Management has prepared the consolidated financial statements of Petrocapita Income Trust in accordance with International Financial Reporting Standards ("IFRS").

Management is responsible for the integrity and objectivity of the financial information. Where necessary, the consolidated financial statements include estimates that are based on management's informed judgments. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized, and reliable accounting records are produced for financial purposes.

Collins Barrow Calgary LLP, an independent firm of Chartered Accountants, was appointed by the Trust's unitholders to conduct an audit of the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Trustees is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board meets regularly with management and has met with the independent auditors to ensure that managements' responsibilities are properly discharged, to review the consolidated financial statements and has approved the consolidated financial statements.

Stephen Johnston
Managing Director

July 14, 2014

Collins Barrow
Chartered Accountants & Consultants

Collins Barrow Calgary LLP
1400 First Alberta Place
777 – 8th Avenue S.W.
Calgary, Alberta, Canada
T2P 3R5

T. 403.298.1500
F. 403.298.5814
e-mail: calgary@collinsbarrow.com

Independent Auditors' Report

To the Trustees
PetroCapita Income Trust

We have audited the accompanying consolidated financial statements of PetroCapita Income Trust and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2013, and the consolidated statement of operations and comprehensive loss, consolidated statement of changes in unitholders' equity (deficiency) and consolidated statement of cash flows for the year then ended, and 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.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' 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 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 PetroCapita Income Trust and its subsidiaries as at December 31, 2013, and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards.

Collins Barrow Calgary LLP

CHARTERED ACCOUNTANTS

Calgary, Canada
July 14, 2014

Petrocapita Income Trust
Consolidated Balance Sheet
December 31, 2013
(in Canadian dollars)

	Notes	2013	2012
Assets			
Current assets			
Cash		$ 4,569,186	$ 14,582,815
Accounts receivable	13(b)	749,503	244,893
Note receivable	4	36,133	43,633
Prepaid expenses and deposits		85,564	830,935
		5,440,386	15,702,276
Non-current assets			
Property and equipment	5, 6	25,595,315	13,664,664
Exploration and evaluation assets	7	1,952,687	1,906,576
		$ 32,988,388	$ 31,273,516
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	13(c)	$ 1,692,033	$ 897,404
Non-current liabilities			
Decommissioning provisions	8	4,555,788	903,573
Preferred Units	9	29,173,907	28,290,300
		35,421,728	30,091,277
Unitholder's Equity (Deficiency)			
Common Units	10	3,571,402	3,571,402
Equity component of Preferred Units	9	3,241,545	3,143,367
Deficit		(9,246,287)	(5,532,530)
		(2,433,340)	1,182,239
		$ 32,988,388	$ 31,273,516

Commitments (note 15)
Subsequent events (note 16)
See accompanying notes to the consolidated financial statements.

Approved by the Trustees

(signed) “Stephen Johnston”, Trustee

(signed) “David Forrest”, Trustee

Petrocapita Income Trust
Consolidated Statement of Operations and Comprehensive Loss
Years Ended December 31, 2013 and 2012
(in Canadian dollars)

	Notes	2013	2012
Revenue			
Petroleum revenue		$ 8,809,789	$ 4,405,889
Royalties		(1,275,246)	(651,319)
		7,534,543	3,754,570
Expenses			
Production and transportation		5,089,668	2,569,364
General and administrative		706,495	554,607
Depletion	6	2,343,101	845,842
		8,139,264	3,969,813
Operating loss		(604,721)	(215,243)
Finance expense, net	11	(3,174,036)	(4,159,374)
Gain on sale of exploration and evaluation assets	7	65,000	-
Net loss and comprehensive loss		(3,713,757)	(4,374,617)
Loss and comprehensive loss attributable to common unit holders		$ (3,713,757)	$ (4,374,617)

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Changes in Unitholders' Equity (Deficiency)
For the Years Ended December 31, 2013 and 2012
(in Canadian dollars)

	Notes	Number of Units	Common Units Stated Value	Equity Component of Preferred Units	Deficit	Total Equity (Deficiency)
Balance at December 31, 2011		5,843,357	$ 3,571,402	$ 1,239,307	$ (1,157,913)	$ 3,652,796
Issuance of Preferred Units	9	-	-	1,904,060	-	1,904,060
Loss and comprehensive loss for the year		-	-	-	(4,374,617)	(4,374,617)
Balance at December 31, 2012		5,843,357	3,571,402	3,143,367	(5,532,530)	1,182,239
Issuance of Preferred Units	9	-	-	98,178	-	98,178
Loss and comprehensive loss for the year		-	-	-	(3,713,757)	(3,713,757)
Balance at December 31, 2013		5,843,357	$ 3,571,402	$ 3,241,545	$ (9,246,287)	$ (2,433,340)

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Cash Flows
For the Years Ended December 31, 2013 and 2012
(in Canadian dollars)

	Notes	2013	2012
Cash provided by (used in):			
Cash flows from operating activities			
Loss for the period		$ (3,713,757)	$ (4,374,617)
Adjustments for:			
Depletion	6	2,343,101	845,842
Net finance expense	11	3,281,496	4,223,543
Gain on sale of exploration and evaluation assets	7	(65,000)	-
Changes in non-cash working capital	12	301,581	463,873
Net cash provided by operating activities		2,147,421	1,158,641
Cash flows from investing activities			
Additions to exploration and evaluation assets	7	(46,111)	(2,804,624)
Acquisition of oil and natural gas interests	5	(8,282,263)	-
Additions to property and equipment	6	(2,362,581)	(4,779,983)
Proceeds from disposition of exploration and evaluation assets	7	65,000	-
Changes in non-cash working capital	12	733,809	(185,066)
Net cash used in investing activities		(9,892,146)	(7,769,673)
Cash flows from financing activities			
Proceeds from issuance of Preferred Units, net of commissions	9	-	16,493,473
Redemption of Preferred Units	9	(109,000)	(25,000)
Interest and Preferred Unit distributions paid	9	(2,167,404)	(1,633,548)
Repayments of note receivable	4	7,500	-
Changes in non-cash working capital	12		(85,000)
Net cash provided by financing activities		(2,268,904)	14,749,925
Change in cash		(10,013,629)	8,138,893
Cash, beginning of period		14,582,815	6,443,922
Cash, end of period		$ 4,569,186	$ 14,582,815

See accompanying notes to the consolidated financial statements.

1. General business description

Petrocapita Income Trust (the "Trust") was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a diversified portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "Partnership"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

The Partnership is managed by the General Partner, Petrocapita GP I Ltd.

The address and principal place of business of the Trust is 803, 5920 Macleod Trail SW, Calgary, Alberta, T2H 0K2.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the Income Tax Act (Canada), the Trust is subject to income taxes only on income that is not distributed or distributable to the unit holders. The Trust, to date, has no undistributed income. As a limited partnership, the income tax consequences of the Trust and ultimately those of the Partnership are deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability is reflected in the consolidated financial statements.

2. Basis of preparation

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the International Financial Reporting Interpretations Committee (IFRIC).

The policies applied in these interim financial statements are based on IFRS issued and outstanding as of July 14, 2014, the date the Trustees approved the statements.

(b) Reporting entity

The consolidated financial statements of the Trust as at and for the year ended December 31, 2013 comprise the Trust and its two subsidiaries, the Partnership and the General Partner, Petrocapita GP 1 Ltd.

(c) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following:

(i) Derivative financial instruments are measured at fair value; and

(ii) Financial instruments designated as "fair value through income (loss)".

The methods used to measure fair values are discussed in note 13.

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Trust's functional currency.

(e) Use of estimates and judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future petroleum and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

Amounts recorded for decommissioning provisions and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates.

The allocation of proceeds on the issuance of preferred units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the preferred units.

The valuation of accounts receivable and note receivable are based on management's best estimate of collectability and the provision for doubtful accounts.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust operates are subject to change.

By their nature, these estimates are subject to measurement uncertainty.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to the periods presented in these consolidated financial statements:

(a) Basis of consolidation:

(i) Subsidiaries

Subsidiaries are entities controlled by the Trust. Control exists when the Trust has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The Trust owns all but 10 of the Partnership's limited partnership units with the other 10 held by the General Partner. The Trust owns 100% of the General Partner and the General Partner cannot be removed except under very limited and specific circumstances. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

(ii) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Jointly controlled assets

Certain assets of the Trust's petroleum and natural gas activities consist of jointly controlled assets. The financial statements include the Trust's proportionate share of these jointly controlled assets and the relevant revenue and related costs.

(c) Business combinations

Business combinations are accounted for using the acquisition method where the acquisition of companies and assets meet the definition of an asset under IFRS. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Following initial recognition, goodwill is recognized at cost less any accumulated impairment losses. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded in earnings as a gain. Associated transaction costs are expensed when incurred.

(d) Exploration and evaluation expenditures and property and equipment

(i) Exploration and evaluation assets

Pre-license expenditures incurred before the Trust has obtained legal rights to explore an area are expensed.

Exploration and evaluation costs include the costs of acquiring licenses, exploratory drilling, geological and geophysical activities, acquisition of mineral and surface rights and technical studies. Exploration and evaluation costs are capitalized as exploration and evaluation assets when the technical feasibility and commercial viability of extracting petroleum and natural gas reserves have yet to be determined. Exploration and evaluation assets are measured at cost and are not depleted or depreciated. Exploration and evaluation assets, net of any impairment loss, are transferred to property and equipment when proved and/or probable reserves are determined to exist.

Exchanges or swaps that involve only exploration and evaluation assets are accounted for at cost. Any gains or losses from the divestiture of exploration and evaluation assets are recognized in income (loss).

(ii) Property and equipment

All costs directly associated with the development and production of petroleum and natural gas interests are capitalized on an area-by-area basis as petroleum and natural gas interests and are measured at cost less accumulated depletion and depreciation and net impairment losses. These costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include property acquisitions with proved and/or probable reserves, development drilling, completion, gathering and infrastructure, decommissioning provisions and transfers of exploration and evaluation assets.

Costs of replacing parts of property and equipment are capitalized only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in income as incurred. The carrying amount of any replaced or sold component is derecognized. The costs of routine maintenance and the day-to-day servicing of property and equipment are recognized in income as incurred.

Exchanges or swaps of property and equipment are measured at fair value unless the transaction lacks commercial substance or neither the fair value of the asset received nor the asset given up can be reliably estimated. When fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gains or losses from the divestiture of property and equipment are recognized in income (loss).

(iii) Depletion and depreciation

Petroleum and natural gas interests are depleted on an area-by-area basis using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs. Production and reserves of natural gas are converted to equivalent barrels of crude oil on the basis of six thousand cubic feet of natural gas to one barrel of oil. Changes in estimates used in prior periods that affect the unit-of-production calculations, such as proved and probable reserves, do not give rise to prior period adjustments and are dealt with on a prospective basis.

Processing facilities and well equipment are depleted using the unit-of-production method along with the related reserves when the assets have a life similar to the reserves of the related wells with little to no residual value. Where facilities and equipment, including major components, are significant in relation to the total cost of the asset and have differing useful lives, they are depreciated separately on a straight-line basis over the estimated useful life of the facilities and equipment and other related components.

(e) Impairment of non-financial assets

The carrying amounts of the Trust's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed for indicators of impairment at each reporting date. If indicators of impairment exist, the recoverable amount of the asset is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property and equipment and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purposes of assessing impairment, exploration and evaluation assets and property and equipment are tested separately and are grouped into cash-generating units ("CGUs"), defined as the lowest levels for which there are separately identifiable independent cash inflows. If, at any time, it is determined that the Trust has no future exploration plans and commercial production cannot be achieved in relation to an area, the associated costs are written down to the estimated recoverable amount, or fully de-recognized and the amount of the write-down is expensed in the statement of operations.

The recoverable amount of a CGU is the greater of its fair value less costs to sell and its value in use. Fair value is determined to be the amount for which the asset could be sold in an arm's length transaction between knowledgeable and willing parties. Fair value less costs to sell may be determined based on discounted future net cash flows of proved and probable reserves using forecast prices and costs and including future development costs. These cash flows are discounted at an appropriate discount rate which would be applied by a market participant. Value in use is determined by estimating the present value of the future net cash flows to be derived from the continued used of the cash-generating unit in its present form. These cash flows are discounted at a rate based on the time value of money and risks specific to the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. An impairment loss recognized in respect of a CGU is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU on a pro rata basis. Impairment losses are recognized in net income (loss).

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Provisions and contingent liabilities

Provisions are recognized by the Trust when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of that obligation. Provisions are stated at the present value of the expenditure expected to settle the obligation. The obligation is not recorded and is disclosed as a contingent liability if it is not probable that an outflow will be required, if the amount cannot be estimated reliably or if the existence of the outflow can only be confirmed by the occurrence of a future event.

(g) Decommissioning provisions

An obligation to incur restoration, rehabilitation and environmental costs arises when environmental disturbance is caused by the exploration, development or ongoing production of petroleum and natural gas properties.

A decommissioning provision is recognized as a liability for obligations associated with the abandonment of petroleum and natural gas wells, removal of equipment from leased acreage and returning such land to its original condition as set by standards of environmental regulations.

The Trust records the fair value of each decommissioning obligation in the period a well or related asset is drilled, constructed or acquired. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate. The expected future cash flows reflect current market assessments and the risks specific to the liability.

The obligation is reviewed regularly by the Trust's management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related property and equipment or exploration and evaluation assets, and a corresponding liability is recognized. The increase in petroleum and natural gas interests is depleted on the same basis as the related petroleum and natural gas component, while the liability is accreted to income until it is settled or sold. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the pre-tax risk-free rate. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or changes in the risk free rate are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision to the extent the provision was established.

(h) Revenue

Revenue from the sale of petroleum and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(i) Finance income and expenses

Finance income, consisting of interest income, is recognized as it accrues in the statement of income, using the effective interest rate method.

Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning provisions, commissions and other costs for the issue of preferred units, distributions paid to Preferred Unit holders, and impairment losses recognized on financial assets.

Borrowing costs incurred for the acquisition or construction of qualifying assets are capitalized during the period required to complete and prepare the assets for their intended use or sale. A qualifying asset is one that takes substantial time to get ready for use or sale.

When funds are borrowed specifically to finance a project, the amount capitalized represents the actual borrowing costs. When the funds used to finance a project form part of general borrowing, the amount capitalized is calculated using the weighted average of rates applicable to the Trust’s relevant general borrowing during the period.

(j) Financial instruments

(i) *Classification and measurement*

Financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as “fair value through income (loss)”, “loans and receivables”, “available-for-sale”, “held-to-maturity”, or “financial liabilities measured at amortized cost” as defined by International Accounting Standards (IAS) 39, *“Financial Instruments: Recognition and Measurement”.*

Financial assets and financial liabilities at “fair value through the statement of income” are either classified as “held for trading” or “designated at fair value through income (loss)” and are measured at fair value with changes in fair value recognized in the income statement. Transaction costs are expensed when incurred. The Trust has designated cash as “held for trading”.

Financial assets and financial liabilities classified as “loans and receivables”, “held-to-maturity”, or “financial liabilities measured at amortized cost” are measured at amortized cost using the effective interest method of amortization. “Loans and receivables” are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. “Held-to-maturity” financial assets are non-derivative investments that an entity has the positive intention and ability to hold to maturity. “Financial liabilities measured at amortized cost” are those financial liabilities that are not designated as “fair value through income (loss)” and that are not derivatives. The Trust has designated accounts receivable, note receivable and deposits as “loans and receivables”, accounts payable and accrued liabilities as “financial liabilities measured at amortized cost” and the liability component of preferred shares as "fair value through income (loss)".

Financial assets classified as “available-for-sale” are measured at fair value, with changes in fair value recognized in other comprehensive income. Available-for-sale financial assets are non-derivatives that are either designated in this category or not classified in any of the other categories.

(ii) *Derivative financial instruments*

The Trust may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. The Trust's policy is not to utilize derivative financial instruments for speculative purposes. All financial derivative contracts are classified as “fair value through income (loss)”.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related. Changes in the fair value of separable embedded derivatives are recognized immediately in the income statement. The Preferred Units have an embedded derivative related to the redemption feature of the units at fair value (note 9).

(iii) *Equity instruments*

Common Units are classified as equity. Incremental costs directly attributable to the issue of units are recognized as a deduction from equity.

Preferred Units are considered to be a hybrid liability and equity instrument with the liability component measured based on the unit holders redemption feature. Upon initial issuance the units are bifurcated into the liability and equity components.

(iv) *Impairment*

The Trust assesses at each balance sheet date whether there is objective evidence that financial assets, other than those designated as "fair value through the statement of income" are impaired. When impairment has occurred, the cumulative loss is recognized in the statement of income. For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the financial asset's original effective interest rate. When an available-for-sale financial asset is considered to be impaired, cumulative gains or losses previously recognized in other comprehensive income are reclassified to the statement of income in the period. Impairment losses may be reversed in subsequent periods.

(k) Recent accounting pronouncements

Changes in accounting policies

On January 1, 2013, the Trust adopted the following new standards and amendments which became effective for annual periods on or after January 1, 2013:

Consolidation

The Trust adopted IFRS 10, Consolidated Financial Statements, effective January 1, 2013. IFRS 10 requires consolidation of an investee only if the investor possesses power over the Investee has exposure or rights to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. The adoption of this standard had no impact on the amounts recorded in the Trust's financial statements.

Joint Arrangement

The Trust adopted IFRS 11, Joint Arrangements, effective January 1, 2013. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation to arrangements where sufficient rights and obligations are passed to the participants. The Trust re-assessed its classification of its joint arrangements and determined that there were no changes in the accounting applied to its joint arrangements.

Disclosure

The Trust adopted IFRS 12, Disclosure of Interests in Other Entities, effective January 1, 2013. IFRS 12 sets out the annual disclosure requirements for the Trust's interests in subsidiaries, joint arrangements and associates. The adoption of IFRS 12 had no impact on the amounts recognized in the Trust's financial statements or note disclosures. The Trust adopted amendments to IFRS 7 Financial Instruments: Disclosures effective January 1, 2013. IFRS 7 has been amended to require annual disclosure of information on rights to offset financial instruments and related arrangements. These amendments had no impact on the Trust's annual disclosures.

Fair Value Measurement

The Trust adopted IFRS 13, Fair Value Measurement, effective January 1, 2013. IFRS 13 improves consistency and reduces complexity by providing a precise definition of fair value and a single source of fair value measurement and disclosure requirements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard had no significant impact on the Trust's financial statements.

The following pronouncements issued by the 1ASB and interpretations published by International Financial Reporting Interpretations Committee (IFRIC) will become effective for annual periods beginning on or after January 1, 2014:

IAS 32, Financial Instruments: Presentation, has been amended to clarify certain requirements for offsetting financial assets and liabilities. The amendment addresses the meaning and application of the concepts of legally enforceable right of set-oft and simultaneous realization and settlement. IAS 32 relates to presentation and disclosures and is not anticipated to have a material impact on the Trust's results and financial position.

IAS 36, Impairment of Assets, has been amended to require disclosure of the recoverable amount of an asset (including goodwill) or a cash generating unit when an impairment loss has been recognized or reversed in the period. When the recoverable amount is based on fair value less costs to sell, the valuation techniques and key assumptions must also be disclosed. The amendment is being assessed to determine its impact on the Trust's financial statement disclosures.

IAS 39, Financial Instruments: Recognition and Measurement, was amended to allow hedge accounting to continue in a situation where a derivative, which has been designated as a hedging instrument, is novated to effect clearing with a central counterparty as a result of laws or regulation, if specific conditions are met (in this context, a novation indicates that parties to a contract agree to replace their original counterparty with a new one). The amendment is not anticipated to have a material impact on the Trust's results or financial position.

IFRIC 21, Levies, on the accounting for levies imposed by governments clarifies the obligating event that gives rise to a liability to pay a levy. IFRIC 21 is effective for annual periods beginning on or after January 1, 2014. IFRIC 21 is being assessed to determine its impact on the Trust's results and financial position.

The following pronouncement has been issued by the IASB, with a tentative effective date.

IFRS 9, Financial Instruments, addresses the classification and measurement of financial assets. IFRS 9 replaces the guidance on 'classification and measurement' of financial instruments in IAS 39, Financial Instruments - Recognition and Measurement. The new standard requires a consistent approach to the classification of financial assets and replaces the numerous categories of financial assets in IAS 39 with two categories, measured at either amortized cost or at fair value. For financial liabilities, the standard retains most of the IAS 39 requirements, but where the fair value option is taken, the part of a fair value change due to an entity's own credit risk is recorded in other comprehensive income rather than the statement of profit and loss, unless this creates an accounting mismatch. It also includes a new general hedge accounting model.

IASB has determined a tentative adoption date for IFRS 9 for annual periods beginning January 1, 2018. IFRS 9, in its current form, as described above, is available for early adoption until IFRS 9R is finalized. IFRS 9 is being assessed to determine its impact on the Trust's results and financial position.

4. Note receivable

A promissory note of $40,000 arising from the exercise of options for Common Units between the Partnership as the lender and a company related through common directors was signed on June 29, 2011. The promissory note bears interest at 6% per annum, accruing daily and compounded and payable annually or as otherwise agreed by both parties; and is redeemable on demand. Total interest of $Nil has been recorded in finance expense for the year ended December 31, 2013 (2012 - $2,400). During the year ended December 31, 2013, $7,500 (2012 - $Nil) in principal repayments were received by the Trust.

5. Asset Acquisitions

During the year ended December 31, 2013, the Trust completed acquisitions of certain conventional producing oil and natural gas assets for $8,282,263 after closing adjustments. The purchases were recognized as business combinations in accordance with IFRS 3 – Business Combinations, as the acquired assets and liabilities assumed constituted a business. The assets acquired are a strategic fit with the Trust's existing asset portfolio because the Trust increased their production in existing areas which increased operational efficiencies and diversified the Trust's product mix. The purchase prices were allocated to the net assets acquired as follows:

Oil and natural gas interests	$ 10,547,963
Decommissioning provisions	(2,265,700)
Total net assets acquired and cash consideration (note 6)	$ 8,282,263

These financial statements incorporate the results of operations of the acquired properties from their closing dates being, March 22, 2013 and April 22, 2013, respectively, onwards. The revenue, operating results and net earnings (loss) attributable to the acquisitions from the respective closing dates to December 31, 2013, as well as the pro forma consolidated revenue, operating results and net earnings (loss) giving effect to the acquisitions as if they had occurred on January 1, 2013, are not practicable to determine. The operations attributable to the acquisitions are not managed as separate business units of divisions of the Trust and general business overhead and other costs of the Trust are not allocated or identified one specific entity basis. Any such allocation would be arbitrary and would require significant assumptions and estimates about what management's intent would have been during those periods.

6. Property and equipment

		Petroleum and Natural Gas Interests and Equipment
Cost		
Balance at December 31, 2011	$	8,986,805
Additions		4,779,983
Transfers from exploration and evaluation assets (note 7)		898,048
Decommissioning provision (note 8)		282,155
Balance at December 31, 2012		14,946,991
Additions		2,362,581
Acquisition of oil and natural gas interests (note 5)		8,282,263
Transfers from exploration and evaluation assets (note 7)		-
Decommissioning provision (note 8)		3,628,908
Balance at December 31, 2013	$	29,220,743
Accumulated depletion		
Balance at December 31, 2011	$	436,485
Depletion for the year		845,842
Balance at December 31, 2012		1,282,327
Depletion for the year		2,343,101
Balance at December 31, 2013	$	3,625,428
Net book value		
Balance at December 31, 2011	**$**	**8,550,320**
Balance at December 31, 2012	**$**	**13,664,664**
Balance at December 31, 2013	**$**	**25,595,315**

(a) Capitalized general and administrative and financing costs

The Trust has not capitalized any general and administrative expenses or interest in the periods ended December 31, 2013 or 2012.

(b) Impairment

Property and equipment was not considered to be impaired at December 31, 2013 or 2012. The future prices used in the impairment test of the Trust cash-generating units at December 31, 2013, were:

	Heavy oil Bow River at Hardisty ($CDN/bbl)
2014	67.12
2015	63.26
2016	63.29
2017	68.28
2018	69.09
2019	69.90
2020	71.75

Prices increase at a rate of approximately 2.0% after 2020. Adjustments were made to the benchmark prices, for purposes of the impairment test, to reflect varied delivery points and quality differentials in the products delivered.

7. Exploration and evaluation assets

Balance at December 31, 2011	$ -
Additions	2,804,624
Transfers to property and equipment (note 6)	(898,048)
Balance at December 31, 2012	1,906,576
Additions	46,111
Balance at December 31, 2013	$ 1,952,687

Intangible exploration and evaluation assets consist of the Trust's exploration projects for which proved reserves have not yet been determined.

Depletion and impairment charges

Exploration and evaluation assets are not depleted or amortized. Any impairment of exploration and evaluation assets, and any eventual reversal thereof, is recognized as additional depletion expense in the income statement. No impairment was recognized during the periods ended December 31, 2013 or 2012.

During the year ended December 31, 2013, the Trust disposed of exploration and evaluation assets with a carrying value of $Nil for proceeds of $65,000.

8. Decommissioning provisions

The future decommissioning obligations were determined by management and were based on the Trust's net ownership interest, the estimated future costs to reclaim and abandon the wells, and the estimated timing of when the costs will be incurred.

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of the decommissioning liability associated with the retirement of petroleum and natural gas properties:

Decommissioning Provision	**2013**	2012
Balance, beginning of period	**$ 903,573**	$ 603,547
Liabilities acquired (note 5)	**2,265,700**	200,972
Change in estimated cash flows	**1,363,208**	81,182
Accretion	**23,307**	17,872
Balance, end of period	**$ 4,555,788**	$ 903,573

The total undiscounted amount of estimated cash flows required to settle the obligation as at December 31, 2013 was $5,515,914 (2012 - $1,062,341) which has been discounted using a risk free rate of 2.77% at December 31, 2013 (2.49% at December 31, 2012). An inflation rate of 2% has been used throughout. All of these obligations are estimated to be incurred in the years 2019 to 2032 and will be funded from general Trust resources at the time of the retirement.

9. Preferred units

Authorized - Unlimited number of Preferred Units

Each preferred unit holder is entitled to one vote per unit but may only vote on matters related to the rights of the preferred unitholders. Such unit holders shall be entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees. If distributions in excess of $0.1025 are declared in any year, the preferred unit holders will receive 10% of the excess distribution up to a maximum of $0.0175 per preferred unit. Subject to certain limitations, preferred unitholders are entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All preferred units are redeemable on demand by the unit holder or the Trust. If the redemption is demanded by the Trust the redemption amount is the original capital plus cumulative dividends. If the redemption is demanded by the unit holder the redemption price is determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust may also convert the preferred unit to a common unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units are considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units are bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative is the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument is measured at the redemption amount that is payable at the end of the reporting period if the holder exercised its right to redeem the unit.

Quarterly distributions were paid to all outstanding preferred unitholders as at Mar 31, 2013, June 30, 2013, September 31, 2013 and December 31, 2013. A distribution re-investment program ("DRIP") was initiated in September of 2011 and the first re-investment of distributions took place on September 30, 2011. A total of $3,258,189 was paid out in distributions in 2013 (2012 - $2,367,915) with $1,090,785 (2012 - $709,367) being re-invested in preferred shares.

In May 2012, the Trust issued an offering memorandum for a maximum of 30,000,000 (2011 – 30,000,000) preferred units priced at a $1.00 (2011 - $1.00) per unit. Proceeds of $18,346,615 (2011 - $10,892,443) were received from the issue of 18,346,615 (2011 – 10,892,443) units from closings during 2012.

During the year, the Trust redeemed 109,000 (2012 - 25,000) Preferred Units at a price $0.90 (2012 - $0.90) per preferred unit. The redemption was accounted for as a reduction in the Preferred Units liability of $98,100 (2012 - $22,500) and a reduction in the equity component of Preferred Units of $10,900 (2012 - $2,500). The excess of the carrying value over the redemption price of $10,900 (2012 - $2,500) was recorded as a component of finance expenses.

	Number of units	Total Amount	Equity Component	Liability Component
Issued and Outstanding Preferred Units				
Balance at December 31, 2011	12,393,073	$12,393,073	$ 1,239,307	$ 11,153,765
Issuance by Offering Memorandum	18,356,227	18,356,227	1,835,623	16,520,606
Redemption of shares	(25,000)	(25,000)	(2,500)	(22,500)
Issuance by way of DRIP	709,367	709,367	70,937	638,430
Balance at December 31, 2012	31,433,667	31,433,667	3,143,367	28,290,300
Redemption of Shares	(109,000)	(109,000)	(10,900)	(98,100)
Issuance by way of DRIP	1,090,785	1,090,785	109,078	981,707
Balance at December 31, 2013	32,415,452	$ 32,415,452	$ 3,241,545	$ 29,173,907

10. Common units

Authorized - Unlimited number of Common Units

Each unit holder is entitled to one vote per unit and shall be entitled to receive non-cumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust.

11. Finance (income) expenses

	2013	2012
Commissions and other costs for the issue of preferred units	**$ -**	$ 1,838,369
Distributions paid to preferred unit holders	**3,258,189**	2,367,915
Accretion of decommissioning provisions	**23,307**	17,872
Interest income	**(107,460)**	(64,169)
	$ 3,174,036	$ 4,159,374

12. Supplemental cash flow information

Changes in non-cash working capital are comprised of:

	2013	2012
Cash provided by (used in):		
Accounts receivable, subscriptions receivable and notes receivable	**$ (504,610)**	$ 871,168
Prepaid expenses and deposits	**745,371**	(103,501)
Accounts payable and accrued liabilities	**794,629**	(573,879)
	$ 1,035,390	$ 193,807
Related to:		
Operating activities	**$ 301,581**	$ 463,873
Investing activities	**733,809**	(185,066)
Financing activities	**-**	(85,000)
Changes in non-cash working capital	**$ 1,035,390**	$ 193,807

The following non-cash transactions have been excluded from the consolidated statement of cash flows in 2013:

- Re-invested distributions of $1,090,785 (2012 - $709,367) from the Trust's DRIP into preferred units.

13. Financial risk management

(a) Overview

The Trust's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Trust employs risk management strategies and polices to ensure that any exposure to risk is in compliance with the Trust's business objectives and risk tolerance levels. While the Board of Trustees has the overall responsibility for the establishment and oversight of the Trust's risk management framework, management has the responsibility to administer and monitor these risks.

(b) Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations. Substantially all of the Trust's accounts receivable are due from petroleum and natural gas marketers and are subject to normal credit risk.

The maximum exposure to credit risk at December 31, 2013 is the following amounts:

	2013	2012
Cash	**$ 4,569,186**	$ 14,582,815
Note receivable	**36,133**	43,633
Accounts receivable	**749,503**	244,893
Maximum exposure to credit risk	**$ 5,354,822**	$ 14,871,341

Accounts receivable

All of the Trust's operations are conducted in Canada. The Trust's exposure to credit risk is influenced mainly by the individual characteristics of each customer. Significant changes in industry conditions and risks that negatively impact customers' ability to generate cash flow will increase the risk of not collecting receivables. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit.

The Trust markets its petroleum and natural gas to primarily one petroleum and natural gas marketer. Due to the small size of the Trust, it is efficient to market all of its petroleum and natural gas to one marketer. Management monitors the credit rating with its marketer to ensure no collection issues arise. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production.

The Trust does not have an allowance for doubtful accounts as at December 31, 2013 or 2012 and did not write-off any receivables during the periods then ended. When determining whether past due accounts are collectible, the Trust factors in the past credit history of the counterparties. The Trust considers all amounts greater than 90 days as past due.

The Trust's accounts receivable were comprised of the following amounts:

	2013	2012
Petroleum revenue	**$ 650,413**	$ 199,540
Capital	**-**	-
Other	**99,090**	45,353
Total accounts receivable	**$ 749,503**	$ 244,893

The accounts receivable is aged as follows:

	2013	2012
Current	**$ 749,503**	$ 236,244
31 – 60 days	**-**	7,975
61 – 90 days	**-**	-
Greater than 90 days	**-**	674
	$ 749,503	$ 244,893

Cash

The Trust manages the credit exposure related to cash by selecting financial institutions with high credit ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(c) Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust’s approach to managing liquidity is to ensure it will have sufficient liquidity to meet its liabilities when due. The Trust's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations.

The Trust's financial liabilities consist of accounts payable and accrued liabilities and preferred units. Accounts payable consists of invoices payable to trade suppliers for operating (e.g., general, administrative, royalty, production and transportation), capital (e.g., drilling, completion and equipping of oil wells) and financing (commissions and other costs for the issue of preferred units) expenditures and are paid within one year. The preferred units are redeemable at the option of the holder and accrue cumulative distributions at $0.1025 per unit per year.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Trust prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures. Refer to note 13(f) for further disclosure on the management of capital.

The Trust's accounts payable and accrued liabilities are aged as follows:

	2013	2012
0 - 30 days	**$ 1,692,032**	**$ 763,197**
31 to 60 days	**-**	**51,531**
61 to 90 days	**-**	**16,055**
Greater than 90 days	**-**	**66,620**
Total accounts payable and accrued liabilities	**$ 1,692,032**	**$ 897,403**

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year. The Trust expects to only redeem the Preferred Units if demanded by the holder in accordance with the terms of the units.

(d) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the years ended December 31, 2013 and 2012 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Once petroleum production levels increase, the Trust may economically hedge some petroleum and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts when deemed appropriate. The Trust will not apply hedge accounting for these contracts. The Trust's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

Foreign currency risk

Prices for petroleum are determined in global markets and generally denominated in United States dollars. The Trust had no forward exchange rate contracts in place nor any working capital items denominated in foreign currencies as at or during the years ended December 31, 2013 and 2012. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of petroleum and natural gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of petroleum and natural gas commodities. The impact of such exchange rate fluctuations on the Trust's net income (loss) cannot be accurately quantified.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust has no interest bearing debt at December 31, 2013 or 2012 and the preferred unit distributions are at a fixed amount per unit. Consequently the Trust is not directly exposed to material interest rate risk. However, inherently, changes in interest rates may affect the general economy. The Trust had no interest rate swaps or financial contracts in place as at or during the years ended December 31, 2013 or 2012.

(e) Fair value of financial instruments

The fair values of note receivable, accounts receivable, deposits and accounts payable and accrued liabilities approximate their carrying values due to the relatively short-term nature of these instruments.

The significance of inputs used in making fair value measurements are examined and classified according to a fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly, and are based on valuation models and techniques where the inputs are derived from quoted indices. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

Cash is measured at fair value based on Level 1 inputs and the liability component of the preferred units is measured at fair value based on Level 2 inputs.

(f) Capital management

The Trust's capital is defined to be unit holders' equity, credit facilities and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments.

The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis:

Balance sheet component	**2013**	2012
Cash	**$ 4,569,186**	$ 14,582,815
Note receivable	**36,133**	43,633
Accounts receivable	**749,503**	244,893
Prepaid expenses and deposits	**85,564**	830,935
Accounts payable and accrued liabilities	**(1,692,032)**	(897,403)
Working capital	**$ 3,748,354**	$ 14,804,873

The Trust is not subject to any externally imposed capital requirements other than the redemption feature of the Preferred and Common Units (notes 9 and 10).

14. Personnel expenses

The total remuneration for employees included in general and administrative expenses was $177,958 (2012 - $137,913). No remuneration was paid to executive officers and directors.

15. Commitments

The Trust has entered into lease agreements for office space which expire in June and September 2015. The required lease payments, exclusive of operating costs, over the remaining term of the leases are as follows:

2014 - $54,485
2015 - $31,965

16. Subsequent events

On March 31, 2014, the Trust approved a first quarter distribution to all outstanding preferred unitholders. A total distribution of $819,268 was approved with $284,423 being re-invested in Preferred Units as part of the DRIP program.

Petrocapita Income Trust

Consolidated Financial Statements

December 31, 2012

Management's Report

Management has prepared the consolidated financial statements of Petrocapita Income Trust in accordance with International Financial Reporting Standards ("IFRS").

Management is responsible for the integrity and objectivity of the financial information. Where necessary, the consolidated financial statements include estimates that are based on management's informed judgments. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized, and reliable accounting records are produced for financial purposes.

Collins Barrow Calgary LLP, an independent firm of Chartered Accountants, was appointed by the Trust's unitholders to conduct an audit of the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Trustees is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board meets regularly with management and has met with the independent auditors to ensure that managements' responsibilities are properly discharged, to review the consolidated financial statements and has approved the consolidated financial statements.

Stephen Johnston
Managing Director

May 20, 2013

Collins Barrow
Chartered Accountants & Consultants

Collins Barrow Calgary LLP
1400 First Alberta Place
777 – 8th Avenue S.W.
Calgary, Alberta, Canada
T2P 3R5

T. 403.298.1500
F. 403.298.5814
e-mail: calgary@collinsbarrow.com

Independent Auditors' Report

To the Trustees
PetroCapita Income Trust

We have audited the accompanying consolidated financial statements of PetroCapita Income Trust and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2012, and the consolidated statement of operations and comprehensive loss, statement of changes in unitholders' equity and statement of cash flows for the year then ended, and 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.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' 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 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 PetroCapita Income Trust and its subsidiaries as at December 31, 2012, and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards.

Collins Barrow Calgary LLP

CHARTERED ACCOUNTANTS

Calgary, Canada
May 20, 2013

Petrocapita Income Trust
Consolidated Balance Sheet
December 31, 2012
(in Canadian dollars)

	Notes	2012	2011
Assets			
Current assets			
Cash		$ 14,582,815	$ 6,443,922
Note receivable	4	43,633	41,233
Accounts receivable	12(b)	244,893	1,118,461
Prepaid expenses and deposits		830,935	727,434
		15,702,276	8,331,050
Non-current assets			
Property and equipment	5	13,664,664	8,550,320
Exploration and evaluation assets	6	1,906,576	-
		$ 31,273,516	$ 16,881,370
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12(c)	$ 897,403	1,471,262
Non-current liabilities			
Decommissioning provisions	7	903,573	603,547
Preferred Units	8	28,290,301	11,153,765
		30,091,277	13,228,574
Equity			
Common Units	9	3,571,402	3,571,402
Equity component of Preferred Units	8	3,143,367	1,239,307
Deficit		(5,532,530)	(1,157,913)
		1,182,239	3,652,796
		$ 31,273,516	$ 16,881,370

Commitments (Note 14)
Subsequent events (Note 15)
See accompanying notes to the consolidated financial statements.

Approved by the Trustees

(signed) "Stephen Johnston", Trustee

(signed) "Leigh Stewart", Trustee

Petrocapita Income Trust
Consolidated Statement of Operations and Comprehensive Loss
Years Ended December 31, 2012 and 2011
(in Canadian dollars)

	Notes	2012	2011
Revenue			
Petroleum revenue		$ 4,405,889	$ 1,747,837
Royalties		(651,319)	(435,327)
		3,754,570	1,312,510
Expenses			
Production and transportation		2,569,364	642,303
General and administrative		554,607	238,822
Depletion	5	845,842	390,486
		3,969,813	1,271,611
Operating income (loss)		(215,243)	40,899
Finance expense, net	10	4,159,374	1,788,048
Net loss and comprehensive loss		(4,374,617)	(1,747,149)
Loss and comprehensive loss attributable to non-controlling interests	5 and 9	-	645,611
Loss and comprehensive loss attributable to common unit holders		$ (4,374,617)	$ (1,101,538)

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Changes in Unitholders' Equity
For the Years Ended December 31, 2012 and 2011
(in Canadian dollars)

	Notes	Number of Units	Common Units Stated Value	Equity Component of Preferred Units	Non-controlling Interests	Deficit	Total Equity
Balance at December 31, 2010		1,110,000	$ 111,000	$ 144,460	$ 216,065	$ (56,375)	$ 415,150
Issuance of Preferred Units	8	-	-	1,094,847	-	-	1,094,847
Exchange of non-controlling interest in the Partnership to Common Units		4,733,357	3,460,402	-	429,546	-	3,889,948
Loss and comprehensive loss for the year		-	-	-	(645,611)	(1,101,538)	(1,747,149)
Balance at December 31, 2011		5,843,357	3,571,402	1,239,307	-	(1,157,913)	3,652,796
Issuance of Preferred Units	8	-	-	1,904,060	-	-	1,904,060
Loss and comprehensive loss for the year		-	-	-	-	(4,374,617)	(4,374,617)
Balance at December 31, 2012		5,843,357	$ 3,571,402	$ 3,143,367	$ -	$ (5,532,530)	$ 1,182,239

See accompanying notes to the consolidated financial statements.

Petrocapita Income Trust
Consolidated Statement of Cash Flows
For the Years Ended December 31, 2012 and 2011
(in Canadian dollars)

	Notes	2012	2011
Cash provided by (used in):			
Cash flows from operating activities			
Loss for the period		$ (4,374,617)	$ (1,101,538)
Adjustments for:			
Depletion	5	845,842	390,486
Loss attributable to non-controlling interests		-	(645,611)
Net finance expense	10	4,220,543	1,799,868
Changes in non-cash working capital	11	463,873	(542,033)
Net cash provided by operating activities		1,155,641	(98,828)
Cash flows from investing activities			
Additions to exploration and evaluation assets	6	(2,804,624)	-
Additions to property and equipment	5	(4,779,983)	(3,410,994)
Changes in non-cash working capital	11	(185,066)	(145,516)
Net cash used in investing activities		(7,769,673)	(3,556,510)
Cash flows from financing activities			
Proceeds from issuance of Preferred Units, net of commissions	8	16,493,473	9,721,633
Proceeds from issuance of Partnership Units to non-controlling interests	9	-	40,000
Interest and Preferred Unit distributions paid	8	(1,658,548)	(561,380)
Changes in non-cash working capital	11	(85,000)	334,215
Net cash provided by financing activities		14,752,925	9,534,498
Change in cash		8,138,893	5,879,160
Cash, beginning of period		6,443,922	564,762
Cash, end of period		$ 14,582,815	$ 6,443,922

See accompanying notes to the consolidated financial statements.

1. General business description

Petrocapita Income Trust (the "Trust") was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a diversified portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "Partnership"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

The Partnership is managed by the General Partner, Petrocapita GP I Ltd.

The address and principal place of business of the Trust is 803, 5920 Macleod Trail SW, Calgary, Alberta, T2H 0K2.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the Income Tax Act (Canada), the Trust is subject to income taxes only on income that is not distributed or distributable to the unit holders. The Trust, to date, has no undistributed income. As a limited partnership, the income tax consequences of the Trust and ultimately those of the Partnership are deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability is reflected in the consolidated financial statements.

2. Basis of preparation

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the International Financial Reporting Interpretations Committee (IFRIC).

The policies applied in these interim financial statements are based on IFRS issued and outstanding as of May 20, 2013, the date the Board of Directors approved the statements.

(b) Reporting entity

The consolidated financial statements of the Trust as at and for the year ended December 31, 2012 comprise the Trust and its two subsidiaries, the Partnership and the General Partner, Petrocapita GP 1 Ltd.

(c) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following:

(i) Derivative financial instruments are measured at fair value; and

(ii) Financial instruments designated as "fair value through income (loss)".

The methods used to measure fair values are discussed in note 12(e).

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Trust's functional currency.

(e) Use of estimates and judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future oil and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

Amounts recorded for decommissioning provisions and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

The allocation of proceeds on the issuance of preferred units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the preferred units.

The valuation of accounts receivable and note receivable are based on management's best estimate of collectability and the provision for doubtful accounts.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust operates are subject to change.

By their nature, these estimates are subject to measurement uncertainty.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to the periods presented in these consolidated financial statements:

(a) Basis of consolidation:

(i) Subsidiaries

Subsidiaries are entities controlled by the Trust. Control exists when the Trust has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The Trust owns all but 10 of the Partnership's 5,833,392 units with the other 10 held by the General Partner. The Trust owns 100% of the General Partner and the General Partner cannot be removed except under very limited and specific circumstances. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

(ii) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Jointly controlled assets

Certain assets of the Trust's petroleum and natural gas activities consist of jointly controlled assets. The financial statements include the Trust's proportionate share of these jointly controlled assets and the relevant revenue and related costs.

(c) Business combinations

Business combinations are accounted for using the acquisition method where the acquisition of companies and assets meet the definition of an asset under IFRS. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Following initial recognition, goodwill is recognized at cost less any accumulated impairment losses. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded in earnings as a gain. Associated transaction costs are expensed when incurred.

(d) Cash and cash equivalents

Cash and cash equivalents consist of amounts on deposit with banks, term deposits and other similar short-term highly liquid investments with maturities of 90 days or less at the date of issuance. Bank overdrafts that are repayable on demand and form an integral part of the Trust's cash management are included as a component of cash and cash equivalents. The Trust did not have any cash equivalents as at December 31, 2012 or 2011.

(e) Exploration and evaluation expenditures and property and equipment

(i) Exploration and evaluation assets

Pre-license expenditures incurred before the Trust has obtained legal rights to explore an area are expensed.

Exploration and evaluation costs include the costs of acquiring licenses, exploratory drilling, geological and geophysical activities, acquisition of mineral and surface rights and technical studies. Exploration and evaluation costs are capitalized as exploration and evaluation assets when the technical feasibility and commercial viability of extracting petroleum and natural gas reserves have yet to be determined. Exploration and evaluation assets are measured at cost and are not depleted or depreciated. Exploration and evaluation assets, net of any impairment loss, are transferred to property and equipment when proved and/or probable reserves are determined to exist.

Exchanges or swaps that involve only exploration and evaluation assets are accounted for at cost. Any gains or losses from the divestiture of exploration and evaluation assets are recognized in income (loss).

(ii) Property and equipment

All costs directly associated with the development and production of petroleum and natural gas interests are capitalized on an area-by-area basis as petroleum and natural gas interests and are measured at cost less accumulated depletion and depreciation and net impairment losses. These costs include expenditures for areas where technical feasibility and commercial viability has been determined. These costs include property acquisitions with proved and/or probable reserves, development drilling, completion, gathering and infrastructure, decommissioning provisions and transfers of exploration and evaluation assets.

Costs of replacing parts of property and equipment are capitalized only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in income as incurred. The carrying amount of any replaced or sold component is derecognized. The costs of routine maintenance and the day-to-day servicing of property and equipment are recognized in income as incurred.

Exchanges or swaps of property and equipment are measured at fair value unless the transaction lacks commercial substance or neither the fair value of the asset received nor the asset given up can be reliably estimated. When fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gains or losses from the divestiture of property and equipment are recognized in income (loss).

(iii) Depletion and depreciation

Petroleum and natural gas interests are depleted on an area-by-area basis using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs. Production and reserves of natural gas are converted to equivalent barrels of crude oil on the basis of six thousand cubic feet of natural gas to one barrel of oil. Changes in estimates used in prior periods that affect the unit-of-production calculations, such as proved and probable reserves, do not give rise to prior period adjustments and are dealt with on a prospective basis.

Processing facilities and well equipment are depleted using the unit-of-production method along with the related reserves when the assets have a life similar to the reserves of the related wells with little to no residual value. Where facilities and equipment, including major components, are significant in relation to the total cost of the asset and have differing useful lives, they are depreciated separately on a straight-line basis over the estimated useful life of the facilities and equipment and other related components.

(f) Impairment of non-financial assets

The carrying amounts of the Trust's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed for indicators of impairment at each reporting date. If indicators of impairment exist, the recoverable amount of the asset is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property and equipment and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purposes of assessing impairment, exploration and evaluation assets and property and equipment are tested separately and are grouped into cash-generating units ("CGUs"), defined as the lowest levels for which there are separately identifiable independent cash inflows. If, at any time, it is determined that the Trust has no future exploration plans and commercial production cannot be achieved in relation to an area, the associated costs are written down to the estimated recoverable amount, or fully de-recognized and the amount of the write-down is expensed in the statement of operations.

The recoverable amount of a CGU is the greater of its fair value less costs to sell and its value in use. Fair value is determined to be the amount for which the asset could be sold in an arm's length transaction between knowledgeable and willing parties. Fair value less costs to sell may be determined based on discounted future net cash flows of proved and probable reserves using forecast prices and costs and including future development costs. These cash flows are discounted at an appropriate discount rate which would be applied by a market participant. Value in use is determined by estimating the present value of the future net cash flows to be derived from the continued used of the cash-generating unit in its present form. These cash flows are discounted at a rate based on the time value of money and risks specific to the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. An impairment loss recognized in respect of a CGU is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU on a pro rata basis. Impairment losses are recognized in net income (loss).

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(g) Provisions and contingent liabilities

Provisions are recognized by the Trust when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of that obligation. Provisions are stated at the present value of the expenditure expected to settle the obligation. The obligation is not recorded and is disclosed as a contingent liability if it is not probable that an outflow will be required, if the amount cannot be estimated reliably or if the existence of the outflow can only be confirmed by the occurrence of a future event.

(h) Decommissioning provisions

An obligation to incur restoration, rehabilitation and environmental costs arises when environmental disturbance is caused by the exploration, development or ongoing production of petroleum and natural gas properties.

A decommissioning provision is recognized as a liability for obligations associated with the abandonment of petroleum and natural gas wells, removal of equipment from leased acreage and returning such land to its original condition as set by standards of environmental regulations.

The Trust records the fair value of each decommissioning obligation in the period a well or related asset is drilled, constructed or acquired. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate. The expected future cash flows reflect current market assessments and the risks specific to the liability.

The obligation is reviewed regularly by the Trust's management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related property and equipment or exploration and evaluation assets, and a corresponding liability is recognized. The increase in petroleum and natural gas interests is depleted on the same basis as the related petroleum and natural gas component, while the liability is accreted to income until it is settled or sold. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the pre-tax risk-free rate. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or changes in the risk free rate are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision to the extent the provision was established.

(i) Revenue

Revenue from the sale of petroleum and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(j) Finance income and expenses

Finance income, consisting of interest income, is recognized as it accrues in the statement of income, using the effective interest rate method.

Finance expense comprises interest expense on borrowings and debentures, accretion of the discount on decommissioning provisions, commissions and other costs for the issue of preferred units, distributions paid to Preferred Unit holders, and impairment losses recognized on financial assets.

Borrowing costs incurred for the acquisition or construction of qualifying assets are capitalized during the period required to complete and prepare the assets for their intended use or sale. A qualifying asset is one that takes substantial time to get ready for use or sale.

When funds are borrowed specifically to finance a project, the amount capitalized represents the actual borrowing costs. When the funds used to finance a project form part of general borrowing, the amount capitalized is calculated using the weighted average of rates applicable to the Trust's relevant general borrowing during the period.

(k) Financial instruments

(i) *Classification and measurement*

Financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "fair value through income (loss)", "loans and receivables", "available-for-sale", "held-to-maturity", or "financial liabilities measured at amortized cost" as defined by International Accounting Standards (IAS) 39, *"Financial Instruments: Recognition and Measurement".*

Financial assets and financial liabilities at "fair value through the statement of income" are either classified as "held for trading" or "designated at fair value through income (loss)" and are measured at fair value with changes in fair value recognized in the income statement. Transaction costs are expensed when incurred. The Trust has designated cash as "held for trading".

Financial assets and financial liabilities classified as "loans and receivables", "held-to-maturity", or "financial liabilities measured at amortized cost" are measured at amortized cost using the effective interest method of amortization. "Loans and receivables" are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. "Held-to-maturity" financial assets are non-derivative investments that an entity has the positive intention and ability to hold to maturity. "Financial liabilities measured at amortized cost" are those financial liabilities that are not designated as "fair value through income (loss)" and that are not derivatives. The Trust has designated accounts receivable, note receivable and deposits as "loans and receivables", accounts payable and accrued liabilities as "financial liabilities measured at amortized cost" and the liability component of preferred shares as "fair value through income (loss)".

Financial assets classified as "available-for-sale" are measured at fair value, with changes in fair value recognized in other comprehensive income. Available-for-sale financial assets are non-derivatives that are either designated in this category or not classified in any of the other categories.

(ii) *Derivative financial instruments*

The Trust may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. The Trust's policy is not to utilize derivative financial instruments for speculative purposes. All financial derivative contracts are classified as "fair value through income (loss)".

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related. Changes in the fair value of separable embedded derivatives are recognized immediately in the income statement. The Preferred Units have an embedded derivative related to the redemption feature of the units at fair value (note 8).

(iii) *Equity instruments*

Common Units are classified as equity. Incremental costs directly attributable to the issue of units are recognized as a deduction from equity.

Preferred Units are considered to be a hybrid liability and equity instrument with the liability component measured based on the unit holders redemption feature. Upon initial issuance the units are bifurcated into the liability and equity components.

(iv) *Impairment*

The Trust assesses at each balance sheet date whether there is objective evidence that financial assets, other than those designated as "fair value through the statement of income" are impaired. When impairment has occurred, the cumulative loss is recognized in the statement of income. For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the financial asset's original effective interest rate. When an available-for-sale financial asset is considered to be impaired, cumulative gains or losses previously recognized in other comprehensive income are reclassified to the statement of income in the period. Impairment losses may be reversed in subsequent periods.

(l) Recent accounting pronouncements

The Trust has reviewed new and revised accounting standards that have been issued but are not yet effective, and determined that the following may have an impact on the Company:

For the annual periods beginning on or after January 1, 2013, the Trust will be required to adopt the following:

- IFRS 7, *"Financial Instruments"* provides additional information about offsetting of financial assets and liabilities. Additional disclosures will be required to enable users of financial statements to evaluate the effect or potential effect of netting arrangements on the entity's financial position.

- IFRS 10, *"Consolidated Financial Statements"* provides a single model to be applied in control analysis for all investees including special purpose entities.

- IFRS 11, *"Joint Arrangements"* redefines joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint operations will need to be proportionately consolidated and joint ventures to be equity accounted.

- IFRS 12, *"Disclosure of Interests in Other Entities"* combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities.

- IFRS 13 *"Fair Value Measurement"* defines the fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

In addition to the issuance of new standards as detailed above, there have also been amendments to existing standards, which are also effective January 1, 2013, including:

- IAS 1 *"Presentation of Financial Statements",* amended to require presentation of an additional opening balance sheet when an entity applies an accounting policy retrospectively or makes a retrospective restatement or reclassification and to clarify the disclosure requirements.

- IAS 32 *"Financial Instruments: Presentation",* amended to clarify the criteria that should be considered in determining whether an entity has a legally enforceable right of offset in respect of its financial instruments and clarifying the treatment of income taxes related to distributions and transaction costs.

For annual periods beginning on or after January 1, 2015, the Trust will be required to adopt:

- IFRS 9 "Financial Instruments". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

The Trust has not yet completed its assessment and evaluation of the effect of adopting the new and amended standards and the impact it may have on its financial statements.

4. Note receivable

A promissory note of $40,000 between the Partnership as the lender and a company related through common directors was signed on June 29, 2011. The promissory note bears interest at 6% per annum, accruing daily and compounded and payable annually or as otherwise agreed by both parties; and is redeemable on demand. Total interest of $2,400 has been recorded in finance expense for the year ended December 31, 2012 (2011 - $1,233).

5. Property and equipment

		Petroleum and Natural Gas Interests and Equipment
Cost		
Balance at December 31, 2010	$	868,848
Acquisition of limited partnership units		3,849,924
Acquisition of property and equipment		401,522
Additions		3,009,472
Transferred from exploration and evaluation assets (note 6)		398,750
Decommissioning provision (note 7)		458,289
Balance at December 31, 2011		8,986,805
Additions		4,779,983
Transfers from exploration and evaluation assets (note 6)		898,048
Decommissioning provision (note 7)		282,155
Balance at December 31, 2012	**$**	**14,946,991**
Accumulated depletion		
Balance at December 31, 2010	$	45,999
Depletion for the year		390,486
Balance at December 31, 2011		436,485
Depletion for the year		845,842
Balance at December 31, 2012	**$**	**1,282,327**
Net book value		
Balance at December 31, 2011	**$**	**8,550,320**
Balance at December 31, 2012	**$**	**13,664,664**

On June 30, 2011, the Trust entered into a transaction with certain limited partners of the Partnership to acquire the remaining 78% of the limited partnership units in exchange for 4,733,357 common trust units. The fair value of the common units issued was $3,460,402 which was based on discounted cash flows from an independent reserve report (note 9).

The exchange of the common units for the remaining interest in the limited partnership resulted in the acquisition of property and equipment of $3,849,924.

During 2011 the Partnership acquired petroleum and natural gas assets by way of two separate purchase and sale agreements. Effective September 1, 2011 the Trust purchased 80 acres of land in Lloydminster, AB for a total purchase price of $28,571 excluding GST. The land had one potential well. Effective November 1, 2011 the Trust purchased the remaining 50% of 40 acres of land in Edam, SK for a total price of $372,951, net of purchase adjustments, to bring their working interest to 100% in Edam, SK.

Capitalized general and administrative and financing costs

The Trust has not capitalized any general and administrative expenses or interest in the periods ended December 31, 2012 or 2011.

Impairment

Property and equipment was not considered to be impaired at December 31, 2012 or 2011. The future prices used in the impairment test of the Trust cash-generating units at December 31, 2012, were:

	Heavy oil - Bow River at Hardisty ($CDN/bbl)
2013	$69.30
2014	$71.61
2015	$72.38
2016	$75.46
2017	$76.23
2018	$77.00
2019	$78.54

Prices increase at a rate of approximately 2.0% after 2019. Adjustments were made to the benchmark prices, for purposes of the impairment test, to reflect varied delivery points and quality differentials in the products delivered.

6. Exploration and evaluation assets

Balance at December 31, 2010	$ 398,750
Transfers to property and equipment (note 5)	(398,750)
Balance at December 31, 2011	-
Additions	2,804,624
Transfers to property and equipment (note 5)	(898,048)
Balance at December 31, 2012	$ 1,906,576

Intangible exploration and evaluation assets consist of the Trust's exploration projects for which proved reserves have not yet been determined.

Depletion and impairment charges

Exploration and evaluation assets are not depleted or amortized. Any impairment of exploration and evaluation assets, and any eventual reversal thereof, is recognized as additional depletion expense in the income statement. No impairment was recognized during the periods ended December 31, 2012 or 2011.

Capitalized general and administrative and financing costs

The Trust has not capitalized any general and administrative expenses or interest in the periods ended December 31, 2012 or 2011.

7. Decommissioning provisions

The future decommissioning obligations were determined by management and were based on the Trust's net ownership interest, the estimated future costs to reclaim and abandon the wells, and the estimated timing of when the costs will be incurred.

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of the decommissioning liability associated with the retirement of petroleum and natural gas properties:

Decommissioning Provision	**2012**	2011
Balance, beginning of period	**$ 603,547**	$ 133,601
Liabilities incurred	**200,972**	458,289
Change in estimated cash flows	**81,182**	-
Accretion	**17,872**	11,657
Balance, end of period	**$ 903,573**	$ 603,547

The total undiscounted amount of estimated cash flows required to settle the obligation as at December 31, 2012 was $1,062,341 (2011 - $795,249) which has been discounted using a risk free rate of 2.49% at December 31, 2012 (2.49% at December 31, 2011). An inflation rate of 2% has been used throughout. All of these obligations are estimated to be incurred in the years 2019 to 2032 and will be funded from general Trust resources at the time of the retirement.

8. Preferred units

Authorized - Unlimited number of Preferred Units

Each preferred unit holder is entitled to one vote per unit but may only vote on matters related to the rights of the preferred unitholders. Such unit holders shall be entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees. If distributions in excess of $0.1025 are declared in any year, the preferred unit holders will receive 10% of the excess distribution up to a maximum of $0.0175 per preferred unit. Subject to certain limitations, preferred unitholders are entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All preferred units are redeemable on demand by the unit holder or the Trust. If the redemption is demanded by the Trust the redemption amount is the original capital plus cumulative dividends. If the redemption is demanded by the unit holder the redemption price is determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust may also convert the preferred unit to a common unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units are considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units are bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative is the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument is measured at the redemption amount that is payable at the end of the reporting period if the holder exercised its right to redeem the unit.

Quarterly distributions were paid to all outstanding preferred unitholders as at Mar 31, 2012, June 30, 2012, September 31, 2012 and December 31, 2012. A distribution re-investment program ("DRIP") was initiated in September of 2011 and the first re-investment of distributions took place on September 30, 2011. A total of $2,367,915 was paid out in distributions in 2012 (2011 - $617,408) with $709,367 (2011 - $56,028) being re-invested in preferred shares.

In May 2012, the Trust issued an offering memorandum for a maximum of 30,000,000 (2011 – 30,000,000) preferred units priced at a $1.00 (2011 - $1.00) per unit. Proceeds of $18,346,615 (2011 - $10,892,443) were received from the issue of 18,346,615 (2011 – 10,892,443) units from closings during 2012.

In November 2012, the Trust redeemed 25,000 Preferred Units at a price $0.90 per preferred unit. The redemption was accounted for as a reduction in the Preferred Units liability of $22,500 and a reduction in the equity component of Preferred Units of $2,500. The excess of the carrying value over the redemption price of $2,500 was recorded as a component of finance expenses.

	Number of units	Total Amount	Equity Component	Liability Component
Issued and Outstanding Preferred Units				
Balance at December 31, 2010	1,444,602	$ 1,444,602	$ 144,460	$ 1,300,142
Issuance by Offering Memorandum	10,892,443	10,892,443	1,089,244	9,803,199
Issuance by way of DRIP	56,028	56,028	5,603	50,425
Balance at December 31, 2011	12,393,073	12,393,073	1,239,307	11,153,765
Issuance by Offering Memorandum	18,356,227	18,356,227	1,835,623	16,520,606
Redemption of Shares	(25,000)	(25,000)	(2,500)	(22,500)
Issuance by way of DRIP	709,367	709,367	70,937	638,430
Balance at December 31, 2012	31,433,667	$31,433,667	$ 3,143,367	$ 28,290,301

9. Common units

Authorized - Unlimited number of Common Units

Each unit holder is entitled to one vote per unit and shall be entitled to receive non-cumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust.

Pursuant to a private placement dated February 2, 2010, the Trust issued 1,110,000 Common Units to management for gross proceeds of $111,000.

Effective June 29, 2011 two equity transactions occurred:

- The performance option issued in 2010 as partial consideration for a property acquisition for 833,342 units of the Partnership was exercised at the prescribed strike price of $0.048 per unit. The proceeds from the exercise of the options amounted to $40,000 and consideration was by way of promissory note (note 4).

- All of the Limited Partners in the Partnership, other than the General Partner (Petrocapita GP I Ltd.) and the Trust, exchanged all of their 4,733,357 Partnership units for 4,733,357 common units of the Trust. This exchange includes the 833,342 units issued on exercise of the performance option described above. The former Limited Partners of the Partnership were allocated their proportionate share of the Partnership's net loss for the period prior to the date of the exchange. The common units issued were recorded based on the market value of the units of $3,460,402. Following this exchange the Trust and the General Partner hold 100% of the Partnership Units and the non-controlling interests in the Partnership no longer exist.

10. Finance (income) expenses

	2012	2011
Commissions and other costs for the issue of preferred units	**$ 1,838,369**	$ 1,170,803
Distributions paid to preferred unit holders	**2,367,915**	617,408
Accretion of decommissioning provisions	**17,872**	11,657
Interest income	**(64,169)**	(11,820)
	$ 4,159,374	$ 1,788,048

11. Supplemental cash flow information

Changes in non-cash working capital are comprised of:

	2012	2011
Cash provided by (used in):		
Accounts receivable, subscriptions receivable and notes receivable	**$ 871,168**	$ (755,328)
Prepaid expenses and deposits	**(103,501)**	(724,134)
Accounts payable and accrued liabilities	**(573,879)**	1,166,128
	193,807	(353,334)
Related to:		
Operating activities	**463,873**	(542,033)
Investing activities	**(185,066)**	(145,516)
Financing activities	**(85,000)**	334,215
Changes in non-cash working capital	**$ 193,807**	$ (353,334)

The following non-cash transactions have been excluded from the consolidated statement of cash flows in 2012:

- Re-invested distributions of $709,367 from the Trust's DRIP into preferred units.

The following non-cash transactions have been excluded from the consolidated statement of cash flows in 2011:

- An amount of $3,849,924 added to property and equipment for the issuance of common units to the partners in PetroCapita Oil & Gas LP.
- Re-invested distributions of $56,028 from the Trust's DRIP into preferred units.
- Issuance of Partnership units to non-controlling interest of $40,000 by way of note receivable.

12. Financial risk management

(a) Overview

The Trust's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Trust employs risk management strategies and polices to ensure that any exposure to risk is in compliance with the Trust's business objectives and risk tolerance levels. While the Board of Trustees has the overall responsibility for the establishment and oversight of the Trust's risk management framework, management has the responsibility to administer and monitor these risks.

(b) Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations. Substantially all of the Trust's accounts receivable are due from petroleum and natural gas marketers and are subject to normal credit risk.

The maximum exposure to credit risk at December 31, 2012 is the following amounts:

	2012	2011
Cash	**$ 14,582,815**	$ 6,443,922
Note receivable	**43,633**	41,233
Prepaid expenses and deposits	**830,935**	727,434
Accounts receivable	**244,893**	1,118,461
Maximum exposure to credit risk	**$ 15,702,276**	$ 8,331,050

Accounts receivable

All of the Trust's operations are conducted in Canada. The Trust's exposure to credit risk is influenced mainly by the individual characteristics of each customer. Significant changes in industry conditions and risks that negatively impact customers' ability to generate cash flow will increase the risk of not collecting receivables. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit.

The Trust markets its petroleum and natural gas to primarily one petroleum and natural gas marketer. Due to the small size of the Trust, it is efficient to market all of its petroleum and natural gas to one marketer. Management monitors the credit rating with its marketer to ensure no collection issues arise. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production.

The Trust does not have an allowance for doubtful accounts as at December 31, 2012 or 2011 and did not write-off any receivables during the periods then ended. When determining whether past due accounts are collectible, the Trust factors in the past credit history of the counterparties. The Trust considers all amounts greater than 90 days as past due.

The Trust's accounts receivable were comprised of the following amounts:

	2012	2011
Petroleum revenue	**$ 199,540**	$ 617,151
Capital	**-**	404,854
Other (current – 0-30 days)	**45,353**	94,456
Total accounts receivable	**$ 244,893**	$ 1,118,461

The accounts receivable at December 31, 2012 is aged as follows:

	2012	2011
Current	**$ 236,244**	$ 735,480
31 – 60 days	**7,975**	181,038
61 – 90 days	**-**	76,447
Greater than 90 days	**674**	125,496
	$ 244,893	$ 1,118,461

Cash

The Trust manages the credit exposure related to cash by selecting financial institutions with high credit ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(c) Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust’s approach to managing liquidity is to ensure it will have sufficient liquidity to meet its liabilities when due. The Trust's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations.

The Trust's financial liabilities consist of accounts payable and accrued liabilities and preferred units. Accounts payable consists of invoices payable to trade suppliers for operating (e.g., general, administrative, royalty, production and transportation), capital (e.g., drilling, completion and equipping of oil wells) and financing (commissions and other costs for the issue of preferred units) expenditures and are paid within one year. The preferred units are redeemable at the option of the holder and accrue cumulative distributions at $0.1025 per unit per year.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Trust prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures. Refer to note 12(f) for further disclosure on the management of capital.

The Trust's accounts payable and accrued liabilities are aged as follows:

	2012	2011
0 - 30 days	**$ 763,197**	$ 1,059,945
31 to 60 days	**51,531**	206,447
61 to 90 days	**16,055**	47,164
Greater than 90 days	**66,620**	157,706
Total accounts payable and accrued liabilities	**$ 897,403**	$ 1,471,262

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year. The Trust expects to only redeem the Preferred Units if demanded by the holder in accordance with the terms of the units.

(d) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the years ended December 31, 2012 and 2011 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Once petroleum production levels increase, the Trust may economically hedge some petroleum and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts when deemed appropriate. The Trust will not apply hedge accounting for these contracts. The Trust's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

Foreign currency risk

Prices for petroleum are determined in global markets and generally denominated in United States dollars. The Trust had no forward exchange rate contracts in place nor any working capital items denominated in foreign currencies as at or during the years ended December 31, 2012 and 2011. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of petroleum and natural gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of petroleum and natural gas commodities. The impact of such exchange rate fluctuations on the Trust's net income (loss) cannot be accurately quantified.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust has no interest bearing debt at December 31, 2012 or 2011 and the preferred unit distributions are at a fixed amount per unit. Consequently the Trust is not directly exposed to material interest rate risk. However, inherently, changes in interest rates may affect the general economy. The Trust had no interest rate swaps or financial contracts in place as at or during the years ended December 31, 2012 or 2011.

(e) Fair value of financial instruments

The fair values of note receivable, accounts receivable, deposits and accounts payable and accrued liabilities approximate their carrying values due to the relatively short-term nature of these instruments.

The significance of inputs used in making fair value measurements are examined and classified according to a fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly, and are based on valuation models and techniques where the inputs are derived from quoted indices. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

Cash is measured at fair value based on Level 1 inputs and the liability component of the preferred units is measured at fair value based on Level 2 inputs.

(f) Capital management

The Trust's capital is defined to be unit holders' equity, credit facilities and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments.

The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis:

Balance sheet component	**2012**	2011
Cash	**$ 14,582,815**	$ 6,443,922
Accounts and other receivables	**288,526**	1,159,694
Prepaid expenses and deposits	**830,935**	727,434
Accounts payable and accrued liabilities	**(897,403)**	(1,471,262)
Working capital	**$ 14,804,873**	$ 6,859,788

The Trust is not subject to any externally imposed capital requirements other than the redemption feature of the Preferred and Common Units (notes 8 and 9).

13. Personnel expenses

The total remuneration for employees included in general and administrative expenses was $137,913 (2011 - $NIL). No remuneration was paid to executive officers and directors.

14. Commitments

The Trust has entered into a lease agreement for office space which expires in September 2015. The required lease payments, exclusive of operating costs, over the remaining term of the lease are as follows:

2013 - $37,049
2014 - $37,049
2015 - $24,700

15. Subsequent events

The Trust signed a purchase and sale agreement with an effective date of March 1, 2013 to acquire certain producing oil assets from a third party for total cash consideration of $6,300,000. The acquisition closed on March 13, 2013. All closing adjustments between the effective date and the closing date will be applied to the purchase price of the assets acquired.

The Trust signed a purchase and sale agreement with an effective date of March 1, 2013 to acquire certain producing oil assets from a third party for total cash consideration of $1,875,000. The acquisition closed on April 8, 2013. All closing adjustments between the effective date and the closing date will be applied to the purchase price of the assets acquired.

On March 31, 2013, the Trust approved a first quarter distribution to all outstanding preferred unitholders. A total distribution of $794,452 was approved with $263,442 being re-invested in Preferred Units as part of the DRIP program.

On March 31, 2013, the Trust redeemed 7,000 preferred units at $0.90 per preferred unit for total consideration of $6,300.

APPENDIX B

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("**MD&A**") of Petrocapita Income Trust for each of the financial years ended December 31, 2014 and 2013, respectively, and for the three and six month periods ended June 30, 2015, has been prepared as of the date of this prospectus and should be read in conjunction with the disclosure contained elsewhere in this prospectus and the consolidated financial statements of the Trust for the financial years ended December 31, 2014, 2013 and 2012, respectively, and the three and six month periods ended June 30, 2015 and 2014, included at Appendix A. The financial statements and comparative information have been prepared and presented in accordance with IFRS and are presented in Canadian dollars.

This MD&A contains forward-looking statements that involves various risks, uncertainties and other factors. The forward-looking statements is not historical fact, but rather is based on Petrocapita's current plans, objectives, goals, strategies, estimates, assumptions and projections about Petrocapita's industry, business and future financial results. The Trust's actual results could differ materially from those discussed in such forward-looking statements as a result of these risks and uncertainties, including those set forth in this prospectus under the heading "*Forward-Looking Statements*" and "*Risk Factors*". The results of operations for the periods reflected herein are not necessarily indicative of results that may be expected for future periods, and actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including but not limited to those listed under "Risk Factors" and included elsewhere in this prospectus. See "*Forward-Looking Statements*" and "*Risk Factors*".

This MD&A makes reference to certain terms that do not have any standardized meaning prescribed by IFRS, referred to as "non-IFRS measures". See "*Notice to Investors – Non-IFRS Measures*" at pages 10 and 11 of this prospectus for terms that do not have any standardized meanings prescribed by IFRS.

Production volumes and per unit amounts are presented throughout this MD&A on a "before royalty" or "gross" basis. Unless otherwise stated, and other than per unit amounts, all amounts presented in this MD&A are in thousands of Canadian dollars.

Capitalized terms and abbreviations used in this MD&A and not otherwise defined herein shall have the meanings ascribed thereto under the headings "*Glossary*" and "*Notice to Investors – Unit Abbreviations*", respectively, in this prospectus.

MANAGEMENT'S DISCUSSION AND ANALYSIS – Q2 2015

The following Management's Discussion and Analysis ("**MD&A**") is a review of the operations and current financial position for the quarter ended June 30, 2015 for Petrocapita Income Trust (the "**Trust**" and, together with its subsidiaries, "**Petrocapita**") and should be read in conjunction with the condensed interim consolidated financial statements as at and for the periods ended June 30, 2015 and 2014, together with the notes related thereto (the "**financial statements**"). All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentages and per share amounts or as otherwise noted. The condensed interim financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

Forward Looking Statements

Reference is made to the section entitled "*Forward-Looking Statements*" in the attached prospectus of which this MD&A forms a part, and all cautionary statements made therein apply to this MD&A.

General Business Description

Petrocapita Income Trust was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "**Partnership**"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

Petrocapita GP I Ltd. is the general partner of the Partnership and the administrator of the Trust (the "**General Partner**", or the "**Administrator**", as the context requires).

See "*The Trust and its Subsidiaries*", "*Declaration of Trust*", "*Limited Partnership Agreement*" and "*Administration Agreement*" in the attached prospectus of which this MD&A forms a part.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the *Income Tax Act* (Canada), the Trust is currently subject to income taxes only on income that is not distributed or distributable to the unit holders. That will change if the Trust becomes a "specified investment flow-through" (SIFT) trust for purposes of the *Income Tax Act* (Canada). See "*Taxation of Specified Investment Flow-Through Trusts*" in the attached prospectus of which this MD&A forms a part. The Trust, to date, has no undistributed income. The income tax consequences of the Trust and ultimately those of the Partnership are currently deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability, is reflected in the consolidated financial statements. The consolidated financial statements of the Trust comprise the Trust and its two subsidiaries, the Partnership and the General Partner.

The Partnership's principal activity is the acquisition of, exploration for and the development and production of heavy oil properties in the Manville formation around the Lloydminster area in Alberta and Saskatchewan.

Non-IFRS Measures

In addition to using financial measures prescribed by IFRS, references are made in this MD&A to "Adjusted EBITDA", "operating netback", "operating cash flow", "net debt", "funds flow from operations" and "funds flow netback", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the financial statements of the Trust. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities. Management uses such terms in the evaluation of the Trust's operating and financial performance and to provide Trust unitholders with a measurement of the Trust's efficiency and its ability to generate the cash necessary to fund its capital expenditures, repay debt or pay

distributions. For the meaning of these terms as used by Management, see "*Notice to Investors – Non-IFRS Measures*" at pages 10 and 11 of the attached prospectus of which this MD&A forms a part.

The following table provides a reconciliation of net income (loss) to Adjusted EBITDA.

	Three months ended June 30		**Six months ended June 30**	
($000s)	**2015**	**2014**	**2015**	**2014**
EBITDA				
Net Income (Loss)	142	(630)	(1,234)	(1,394)
Distributions to Shareholders	–	835	848	1,654
Decommissioning Obligations Accretion	33	31	68	63
Depletion and Depreciation	306	596	738	1,238
Interest Income	(3)	(9)	(9)	(21)
Interest on Debenture	3	–	3	–
Preferred Unit Redemptions (Excess Carry Value to Redemption Cost - Preferred Units)	(5)	7	(5)	7
Gain on Sale of Assets	–	–	–	(143)
Gain on Asset acquisition	(71)	–	(71)	–
Gain on Purchase of Assets	(390)	–	(390)	–
Adjusted EBITDA	**16**	**830**	**(52)**	**1,404**

A reconciliation of the cash flow from operating activities and funds flow from operations is as follows:

	Three months ended June 30		**Six months ended June 30**	
($000s)	**2015**	**2014**	**2015**	**2014**
Cash Flow from Operations - IFRS	(217)	640	125	462
Changes in Non-cash Operating Working Capital	243	187	(222)	951
Other Non-cash Operating Working Capital	(10)	12	51	12
Interest Income	(3)	(9)	(9)	(21)
Interest Expense	3	–	3	–
Funds Flow From Operations	**16**	**830**	**(52)**	**1,404**

The forward-looking statements included in this document are expressly qualified by the cautionary statements made in the attached prospectus and are made as of the date of this document. The Trust does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

2015 Overview

See "*General Development of Business – 2015*" in the attached prospectus of which this MD&A forms a part.

Selected Quarterly Information

The following tables highlight Petrocapita's performance for each of the eight quarters ended June 30, 2015:

Financial ($000s)	**Q2 2015**	**Q1 2015**	**Q4 2014**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**
Total Revenue [1]	1,029	892	1,817	2,766	2,995	2,766	2,195	3,772
Funds Flow From Operations [2]	16	(68)	97	754	830	574	(145)	1,376
Net Income (loss)	142	(1,376)	(1,846)	(696)	(630)	(764)	(1,557)	(166)
Capital Expenditures[7]	4,336	273	(337)	600	711	235	676	640
Total Assets	33,647	30,628	31,365	33,037	33,295	32,375	32,988	33,621
Net Debt (surplus)[3]	(169)	(1,749)	(573)	(2,849)	(3,238)	(3,630)	(3,748)	(5,084)

Operating ($000s unless indicated)	**Q2 2015**	**Q1 2015**	**Q4 2014**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**
Total Oil Production (bbls)	20,442	25,734	28,758	34,552	35,299	37,893	39,360	44,009
Total Oil Production (bbls/day)	222	286	313	380	384	421	428	484
Average Realized Oil Price ($ per bbl)	49.30	34.00	59.94	76.97	82.47	71.66	55.50	85.72
Operating Netback ($ per bbl) [2]	10.57	6.48	9.64	27.52	28.96	19.11	2.18	35.38
Oil Revenue [6]	1,008	875	1,724	2,659	2,911	2,715	2,184	3,772
Water Disposal Revenue [4]	21	17	94	107	84	51	11	–
Royalties	(96)	(86)	(298)	(460)	(569)	(398)	(432)	(668)
Production Expense	(673)	(584)	(1,175)	(1,230)	(1,247)	(1,527)	(1,539)	(1,387)
Transportation Expense	(44)	(55)	(68)	(124)	(156)	(116)	(138)	(161)
Operating Netback	216	167	277	952	1,022	724	87	1,557
General and Administrative Expense	(200)	(235)	(180)	(198)	(193)	(150)	(232)	(180)
Funds Flow From Operations [2]	16	(68)	97	754	830	574	(145)	1,376

Water Disposal (included in above totals)

Financial ($000s)	**Q2 2015**	**Q1 2015**	**Q4 2014**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**
Skim Oil Produced (bbls)	290	303	1,650	1,888	906	1,470	177	–
Skim Oil Revenue [5]	4	10	94	145	74	98	8	–
Water Disposed (m3)	6,052	4,747	26,769	30,457	23,947	14,460	3,073	–
Water Disposal Revenue [4]	21	17	94	106	84	51	12	–
Operating ($000s unless indicated)								
Crown Royalties	(1)	–	(11)	(19)	(5)	(13)	–	–
Production Expense	(37)	(29)	(78)	(71)	(57)	(59)	(24)	–
Transportation Expense	(1)	(1)	(5)	(5)	(2)	(1)	(1)	–
Operating Netback	(13)	(3)	94	156	94	76	(5)	–
Operating Netback ($ per m3)	(2.16)	(0.63)	3.5	5.12	3.93	5.26	(1.63)	–

Notes:

(1) Includes heavy oil revenue, skim oil revenue, oil royalty revenue and water disposal revenue
(2) See "*Notice to Investors – Non-IFRS Measures*" in the prospectus (pp. 10-11)
(3) Net Debt equals current liabilities plus indebtedness under outstanding debentures less current assets
(4) Income received from charging third parties for the disposal of water
(5) Income received by selling the oil that is recovered from the water to be disposed (included in Oil Revenue but not included in Water Disposal Revenue)
(6) Includes heavy oil revenue, skim oil revenue and oil royalty revenue
(7) Capital Expenditures net of Asset Retirement Obligations and Accumulated Depletion

Revenue and Production

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Heavy Oil Revenue ($000s)	1,008	2,911	1,883	5,626
Heavy Oil Production (bbls/day)	222	384	255	404
Average Realized Price ($ per bbl)	49.30	82.47	40.77	76.87
Benchmark Prices				
WTI Oil (US$ per bbl) (1)	57.94	102.99	53.29	100.84
WCS Oil (US$ per bbl)) (2)	46.69	85.25	40.40	79.62
Heavy Oil Differential (3)	19%	19%	24%	21%
CAD/USD Average Exchange Rate	1.23	1.09	1.24	1.10

Notes:
(1) WTI refers to the arithmetic average based on NYMEX prompt month WTI (West Texas Intermediate)
(2) WCS refers to the average posting price for the benchmark WCS (Western Canada Select) heavy oil
(3) Heavy oil differential refers to the WCS discount to WTI

Revenue for the three months ended June 30, 2015 was $1 million, compared to $3 million for the three months ended June 30, 2014 representing a 65% decrease. Production decreased from 384 bbls per day in Q2 of 2014 to 222 bbls per day in Q2 of 2015 representing a 42% decline. Revenue and production decreased due to a 40% decrease in the WTI price of oil in the market which is offset partly by the lower Canadian dollar and lower WTI/WCS differential.

Revenue for the six months ended June 30, 2015 was $1.8 million compared to $5.6 million for the six months ended June 30, 2014 representing a 67% decrease. This decrease in revenue is attributed to a 37 % production decrease and a 47% decrease in realized oil pricing. Production decreased from 404 bbls per day for the first six months of 2014 to 255 bbls per day for the same period in 2015. The average realized commodity price decreased from $76.87 per bbl in the six months ended June 30, 2014 to $40.77 per bbl in the comparable period of 2015.

Royalties

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Heavy Oil Revenue ($000s)	1,008	2,911	1,883	5,626
Total Royalties ($000s)	96	569	182	968
Total Royalties ($ per bbl)	4.69	16.12	3.94	13.23
Percent of Oil Revenue	10%	20%	10%	17.%

Royalties for the three months ended June 30, 2015 were $96 thousand, compared to $569 thousand for the three months ended June 30, 2014. Total royalties as a percentage of revenue for the three months ended June 30, 2015 were 10% of oil revenue, as compared to 20% for the same period in 2014. Royalties decreased in Q2 of 2015 over the prior comparative period mostly due to the decrease in commodity price for oil.

Royalties for the six months ended June 30, 2015 were $182 thousand, compared to $968 thousand for the six months ended June 30, 2014. Total royalties as a percentage of revenue for the six months ended June 30, 2015 were 10% of oil revenue, as compared to 17% for the same period in 2014. Royalties decreased for the six months of 2015 mostly due to the decrease in commodity price for oil.

Production and Transportation Expenses

	Three months ended June 30		Six months ended June 30	
($000s unless indicated)	**2015**	**2014**	**2015**	**2014**
Production Expense	673	1,247	1,257	2,775
Transportation Expense	44	156	99	272
Total Production & Transportation Expense	717	1,403	1,356	3,047
Production Expense ($ per bbl)	32.92	35.33	27.22	37.91
Transportation Expense ($ per bbl)	2.15	4.42	2.14	3.72
Total Production & Transportation ($ per bbl)	35.07	39.75	29.37	41.63

Production expense for the three months ended June 30, 2015 was $673 thousand or $32.92 per bbl, compared to $1.2 million or $35.33 per bbl for the three months ended June 30, 2014. This decrease is mostly due to limiting the wells on production in Q2 2015 to only the economic wells.

Production expense for the six months ended June 30, 2015 was $1.2 million or $27.22 per bbl, compared to $2.8 million or $37.91 per bbl for the six months ended June 30, 2014. This decrease is mostly due to limiting the wells on production in Q2 2015 to only the economic wells.

Transportation expense for the three months ended June 30, 2015 was $44,000 or $2.15 per bbl, compared to $156,000 or $4.42 per bbl for the three months ended June 30, 2014. This decrease was mainly due to suspending uneconomic wells due to the lower commodity prices.

Transportation expense for the six months ended June 30, 2015 was $99,000 or $2.14 per bbl, compared to $272,000 or $3.72 per bbl for the six months ended June 30, 2014. This decrease was mainly due to suspending uneconomic wells due to the lower commodity prices.

Operating Netback

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Sales Volume (bbl/day)	222	384	255	404
Oil Revenue ($ per bbl)	49.30	82.47	40.77	76.87
Water Disposal Revenue ($ per bbl)	1.04	2.37	.82	1.84
Less: Royalties ($ per bbl)	(4.69)	(16.12)	(3.94)	(13.23)
Production Expense ($ per bbl)	(32.92)	(35.34)	(27.22)	(37.91)
Transportation Expense ($ per bbl)	(2.15)	(4.42)	(2.14)	(3.72)
Operating Netback ($ per bbl)	10.58	28.96	8.29	23.85
General & Administrative Expense ($ per bbl)	(9.77)	(5.46)	(9.42)	(4.69)
Funds Flow Netback ($ per bbl)	0.81	23.50	(1.13)	19.16

Operating netback for the three months ended June 30, 2015 was $10.58 per bbl, compared to $28.96 per bbl for the three months ended June 30, 2014. Funds flow netback for the three months ended June 30, 2015 was $0.81 per bbl, compared to $23.50 per bbl for the three months ended June 30, 2014. This decrease in netbacks per bbl is mostly due to lower revenue prices. Realized sales price decreased from $82.47 per bbl for the three months ended June 30, 2015 to $49.30 per bbl for the same period ended June 30, 2014. There was a decrease in royalty netbacks from $16.12 per bbl to $4.69 per bbl resulting largely from the lower production volumes. There was a slight decrease of production expense from $35.34 per bbl to $32.92 per bbl largely due to fewer wells being on production.

Operating netback for the six months ended June 30, 2015 was $8.29 per bbl, compared to $23.85 per bbl for the six months ended June 30, 2014. Funds flow netback for the six months ended June 30, 2015 was a loss of $1.13 per bbl, compared to a gain of $19.16 per bbl for the six months ended June 30, 2014. This decrease in netbacks per bbl is mostly due to lower revenue prices and an increase in General and Administrative costs due to the reorganizing of the company. Realized sales price decreased from $76.87 per bbl for the six months ended June 30, 2015 to $40.77 per bbl for the same period ended June 30, 2014. There was a decrease in royalty from $13.23 per bbl to $3.94 per

bbl resulting largely from the lower production volumes. There was a decrease of production expense from $37.91 per bbl to $27.22 per bbl largely due to having only the more economic wells on production while the oil price remains low.

General and Administrative Expenses

	Three months ended June 30		Six months ended June 30	
($000s unless indicated)	**2015**	**2014**	**2015**	**2014**
G & A Expense	216	190	470	345
G & A Recoveries	(16)	3	(35)	(2)
Total G & A Expense	200	193	435	343
Total G & A Expense ($ per bbl)	9.77	5.46	9.42	4.69

General and administrative expense, net of recoveries, was $200,000 or $9.77 per bbl for the three months ended June 30, 2015 compared to $193,000 or $5.46 per bbl for the three months ended June 30, 2014. General and administrative expense increased in 2015 as new staff was added and costs were incurred for reorganizing the Trust.

General and administrative expense, net of recoveries, was $435,000 or $9.42 per bbl for the six months ended June 30, 2015 compared to $343,000 or $4.69 per bbl for the six months ended June 30, 2014. General and administrative expense increased in 2015 as new staff was added and costs were incurred for reorganizing the Trust.

Depletion and Depreciation

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
Depletion ($000s)	306	596	738	1,239
Depletion ($ per bbl)	14.96	16.88	15.98	16.92

Depletion for the three months ended June 30, 2015 was $306 thousand compared to the $596 thousand for the three months ended June 30, 2014. Depletion per bbl was $14.96 for the three months ended June 30, 2015, as compared to $16.88 for the three months ended June 30, 2014. Depletion was lower due to the lower production in the first three months of 2015.

Depletion for the six months ended June 30, 2015 was $0.7 million compared to the $1.2 million for the six months ended June 30, 2014. Depletion per bbl was $15.98 for the six months ended June 30, 2015, as compared to $16.92 for the six months ended June 30, 2014. Depletion was lower due to the lower production in the first six months of 2015.

Finance Expense

	Three months ended June 30		Six months ended June 30	
	2015	**2014**	**2015**	**2014**
($000s)				
Distributions Paid to Preferred Unit Holders	–	835	848	1,654
Redemption Commissions	(3)	7	(5)	7
Accretion of Decommissioning Provision	33	31	68	63
Accretion on Debenture	–	–	–	–
Interest on Debenture	3	–	3	–
Bank Interest Income	(3)	(9)	(9)	(22)
Total Finance Expense	30	864	905	1,702

Finance expense for the three months ended June 30, 2015 was $30 thousand as compared to $864 thousand for the three months ended June 30, 2014. This decrease was mostly due to the conversion, during the quarter ended June 30, 2015, of all previously outstanding preferred trust units to common trust units, which eliminated the distributions payable.

Finance expense for the six months ended June 30, 2015 was $0.9 million as compared to $1.7 million for the six months ended June 30, 2014. This decrease was mostly due to the conversion, during the quarter ended June 30, 2015, of all previously outstanding preferred trust units to common trust units, which eliminated the distributions payable.

Petrocapita's debenture (issued June 1, 2015) and convertible debenture (issued June 30, 2015) both pay an interest rate of 6% annually.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended June 30		**Six months ended June 30**	
($000s)	**2015**	**2014**	**2015**	**2014**
Net Income (Loss)	142	(630)	(1,234)	(1,394)

Net income for the three months ended June 30, 2015 was $142,000, compared to a net loss of $630,000 for the three months ended June 30, 2014. This increase was mostly due to the gains on asset swap and acquisition and the lower financing costs resulting from the cancellation of the distributions.

Net loss for the six months ended June 30, 2015 was $1.2 million, compared to a net loss of $1.4 million for the six months ended June 30, 2014. This increase was mostly due to the gain on asset swap, gain on acquisition and the lower financing costs resulting from the conversion of Preferred Trust Units to Common Trust Units in the second quarter of 2015. This was partly offset by the lower revenues in the first six months of 2015 resulting from lower realized oil prices.

Capital Expenditures

Capital expenditures are summarized as follows:

	Three months ended June 30		**Six months ended June 30**	
	2015	**2014**	**2015**	**2014**
($000s)				
Additions: Land	–	11	3	84
Seismic	–	–	–	–
Drilling and Completion	216	315	441	472
Equipping	483	385	443	390
Asset Acquisitions	3688	–	3,773	–
Asset Dispositions	(51)	–	(51)	–
Total Capital Expenditures	4,336	711	4,609	946
Decommissioning Provision	(227)	265	(11)	685
Cumulative Total Capital Assets	38,362	32,805	38,362	32,805
Accumulated Depletion and Depreciation	(6,657)	(4,865)	(6,657)	(4,865)
Net Book Value of Capital Assets	31,705	27,940	31, 705	27,940

At the end of 2014 Petrocapita decided to substantially reduce its capital spending on drilling and completion of oil wells and focus primarily on expanding produced salt water disposals. The plan for 2015 is to start up 4 water disposal sites at an estimated cost of $1 million dollars. As at June 30, 2015 two (2) water disposal sites have been added with capital costs of $330,000. One of the water disposals brought on in Q2 2015 was acquired in an asset swap.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Trust prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures.

The Trust's accounts payable and accrued liabilities are aged as follows as at June 30:

	2015	2014
0 - 30 days	$ 828,552	$ 1,285,183
31 to 60 days	271,357	9,666
61 to 90 days	9,703	79,110
Greater than 90 days	9,353	968
Total accounts payable and accrued liabilities	$ 1,118,965	$ 1,374,927

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year.

Market risk – Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk – The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the six months ended June 30, 2015 and 2014 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Capital management – The Trust's capital is defined to be unitholders' equity and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments. The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis as at June 30:

	2015	2014
Cash	$ 1,349,041	$ 2,598,148
Accounts receivable	552,595	800,052
Note receivable	13,078	21,790
Prepaid expenses and deposits	27,116	99,712
Accounts payable and accrued liabilities	(1,118,965)	(1,374,927)
Current portion of preferred units	-	(1,572,195)
Working capital	**$ 325,529**	**$ 572,580**

Units of the Trust

Beneficial interests in the Trust are represented and constituted by two classes of Units – being common trust units of the Trust ("**Trust Units**") and preferred trust units of the Trust ("**Preferred Units**") – of which an unlimited number of each class are authorized and may be issued. The rights, privileges, restrictions and conditions attached to the Trust Units and the Preferred Units are set out in the Declaration of Trust.

See "*Declaration of Trust*" in the attached prospectus of which this MD&A forms a part.

Trust Units and Preferred Units, as well as any other securities of the Trust, may be created, issued, sold and delivered at the times, to the persons, for the consideration, and otherwise on the terms and conditions determined by the Trustees in their absolute discretion.

The Trustees may, in their discretion, at any time and from time to time, subdivide or consolidate each or either class of Units outstanding.

Subject to any discounts that the Trustees may allow as consideration for agreeing to subscribe for Units, Units are only to be issued when fully paid, and they are not subject to future calls or assessment; provided, however, that Units issued under an offering may be issued for a consideration payable in instalments and the Trust may take security over any such Units for unpaid instalments. The consideration for any Unit issued by the Trust shall be paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit has been issued for money; provided that property may include a promissory note.

There are no pre-emptive rights attaching to either the Trust Units or the Preferred Units as a class.

Conversion of Preferred Units to Trust Units

Prior to June 21, 2015 there were approximately 33.8 million Preferred Units outstanding. On May 22, 2015, the Trust issued a notice of conversion to the holders of the outstanding Preferred Units pursuant to which, in accordance with the Declaration of Trust, all outstanding Preferred Units were converted to Trust Units effective June 21, 2015 on the basis of approximately 32.6 Trust Units for every one (1) Preferred Unit. As a consequence of that conversion, there are no Preferred Units left outstanding, and the former holders of Preferred Units are deemed to be holders of Trust Units and shall not be entitled to any rights as holders of Preferred Units.

Trust Units

Each holder of Trust Units is entitled to one vote per unit and shall be entitled to receive noncumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust.

There were 1,109,731,962 Trust Units outstanding as at June 30, 2015. There were 5,843,357 outstanding as at June 30, 2014.

Use of Estimates and Judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future petroleum and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

Amounts recorded for decommissioning provisions and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates.

The allocation of proceeds on the issuance of Preferred Units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the Preferred Units.

The valuation of accounts receivable and note receivable are based on management's best estimate of collectability and the provision for doubtful accounts.

The equity portion of the convertible debenture is based upon management's estimate of the interest rate the Trust would pay for non-convertible debt with similar terms.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust operates are subject to change.

By their nature, these estimates are subject to measurement uncertainty.

Changes in Accounting Policies

There were no changes in accounting policies during the period ended June 30, 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS – 2014

The following Management's Discussion and Analysis ("**MD&A**") is a review of the operations and financial position for the year ended December 31, 2014 for Petrocapita Income Trust (the "**Trust**" and, together with its subsidiaries, "**Petrocapita**") and should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2014 and 2013, together with the notes thereto (the "**financial statements**"). All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentages and per share amounts or as otherwise noted. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

Forward Looking Statements

Reference is made to the section entitled "*Forward-Looking Statements*" in the attached prospectus of which this MD&A forms a part, and all cautionary statements made therein apply to this MD&A.

General Business Description

Petrocapita Income Trust was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "**Partnership**"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

Petrocapita GP I Ltd. is the general partner of the Partnership and the administrator of the Trust (the "**General Partner**", or the "**Administrator**", as the context requires).

See "*The Trust and its Subsidiaries*", "*Declaration of Trust*", "*Limited Partnership Agreement*" and "*Administration Agreement*" in the attached prospectus of which this MD&A forms a part.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the *Income Tax Act* (Canada), the Trust is currently subject to income taxes only on income that is not distributed or distributable to the unit holders. That will change if the Trust becomes a "specified investment flow-through" (SIFT) trust for purposes of the *Income Tax Act* (Canada). See "*Taxation of Specified Investment Flow-Through Trusts*" in the attached prospectus of which this MD&A forms a part. The Trust, to date, has no undistributed income. The income tax consequences of the Trust and ultimately those of the Partnership are currently deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability, is reflected in the consolidated financial statements. The consolidated financial statements of the Trust comprise the Trust and its two subsidiaries, the Partnership and the General Partner.

The Partnership's principal activity is the acquisition of, exploration for and the development and production of heavy oil properties in the Manville formation around the Lloydminster area in Alberta and Saskatchewan.

Non-IFRS Measures

In addition to using financial measures prescribed by IFRS, references are made in this MD&A to "Adjusted EBITDA", "operating netback", "operating cash flow", "net debt" and "funds flow from operations", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the financial statements of the Trust. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities. Management uses such terms in the evaluation of the Trust's operating and financial performance and to provide Trust unitholders with a measurement of the Trust's efficiency and its ability to generate the cash necessary to fund its capital expenditures, repay debt or pay distributions. For the meaning of

these terms as used by Management, see "*Notice to Investors – Non-IFRS Measures*" at pages 10 and 11 of the attached prospectus of which this MD&A forms a part.

The following table provides a reconciliation of net income (loss) to Adjusted EBITDA.

	Three months ended December 31		**Twelve months ended December 31**	
($000s)	**2014**	**2013**	**2014**	**2013**
EBITDA				
Net Income (Loss)	(1,846)	(1,557)	(3,937)	(3,714)
Distributions Paid to Preferred Unit Holders	858	831	3,364	3,258
Accretion of Decommissioning Provision	32	6	126	23
Depletion and Depreciation	478	655	2,293	2,343
Bank Interest Income	(9)	(12)	(39)	(97)
Interest on Note Receivable	(4)	–	(4)	–
Preferred Unit Redemptions (Excess Carry Value to Redemption Cost - Preferred Units)	(12)	(2)	(7)	(10)
Gain on Sale of Assets	(15)	(65)	(158)	(65)
Loss on Impairment of Assets	615		615	–
Adjusted EBITDA	**97**	**(145)**	**2,254**	**1,738**

A reconciliation of the cash flow from operating activities and funds flow from operations is as follows:

	Three months ended December 31		**Twelve months ended December 31**	
($000s)	**2014**	**2013**	**2014**	**2013**
Cash Flow from Operations - IFRS	740	425	1,991	2,137
Changes in Non-cash Operating Working Capital	(634)	(558)	302	(302)
Bank Interest Income	(9)	(12)	(39)	(97)
Funds Flow From Operations	97	(145)	2,254	1,738

The forward-looking statements included in this document are expressly qualified by the cautionary statements made in the attached prospectus and are made as of the date of this document. The Trust does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

2014 Overview

See "*General Development of Business – 2014*" in the attached prospectus of which this MD&A forms a part.

Petrocapita initiated a produced water disposal program in 2013 to help lower its operating and transportation costs and create additional cash flow by disposing of third party produced water and recovering skim oil. Petrocapita's first water disposal well initiated operations in November 2013 and a second initiated operations in July 2014. Results of operations of both water disposal wells are included in the 2014 financial statements.

Selected Annual Financial Information

	Years ended December 31		
($000s)	**2014**	**2013**	**2012**
Total Revenue [1]	10,530	8,810	4,406
Funds Flow From Operations [2]	2,254	1,738	631
Net Income (loss)	(3,937)	(3,714)	(4,375)
Operating Netback ($ per bbl)	21.80	18.36	17.31
Total Assets	31,365	32,988	31,274
Total Financial Liabilities	37,623	35,422	30,091
Net Debt [3]	(573)	(3,748)	(14,805)

Selected Quarterly Information

The following table highlights Petrocapita's performance for each of the eight quarters ended December 31, 2014:

($000s)	**Q4 2014**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**	**Q2 2013**	**Q1 2013**
Total Oil Sales (bbls)	28,758	34,552	35,299	37,893	39,360	44,009	34,304	15,500
Total Oil Sales (bbls/day)	313	380	384	421	428	484	373	172
Total Revenue [1]	1,860	2,830	3,035	2,805	2,233	3,772	1,656	1,148
Average Realized Oil Price ($ per bbl)	59.94	76.97	82.47	71.66	55.50	85.72	48.29	74.06
Operating Netback ($ per bbl)[2]	9.64	27.55	28.96	19.11	2.19	35.38	20.78	5.72
Funds Flow From Operations ($ per bbl) [2]	3.36	21.82	23.50	15.15	(3.70	31.28	16.57	(3.95)
Net Income (Loss)	(1,846)	(696)	(630)	(764)	(1,557)	(166)	(801)	(1,190)
Total Assets	31,365	33037	33,295	32,375	32,988	33,621	33,338	30,831
Capital Expenditures	(269)	538	632	314	676	640	2,465	6,909
Water Disposal (included in above totals)								
Water Disposal Revenue [4]	136	170	125	90	49	–	–	–
Water Disposed (m3)	38,898	48,670	35,535	25,780	10,209	–	–	–
Skim Oil Revenue [5]	94	145	74	98	8	–	–	–
Skim Oil Produced (bbls/day)	17.9	20.8	9.8	16.3	1.9	–	–	–
Average Skim Oil Price ($ per bbl)	56.97	76.78	81.66	66.67	45.2	–	–	–
Water Disposal Skim Royalties	(11)	(19)	(5)	(13)	–	–	–	–
Water Disposal Operating Costs	83	76	59	60	25	–	–	–

Notes:

(1) Includes oil revenue, skim oil revenue, oil royalty revenue and water disposal revenue
(2) See "*Notice to Investors – Non-IFRS Measures*" in the prospectus (pp. 10-11)
(3) Net Debt equals current liabilities less current assets
(4) Income received from charging for the disposal of water
(5) Income received by selling the oil that is recovered from the water to be disposed (included in Oil Revenue but not included in Water Disposal Revenue)

2014 Operations

Revenue and Production

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
Heavy Oil Revenue ($000s)	1,724	2,184	10,009	8,761
Heavy Oil Production (bbls/day)	313	428	374	365
Average Realized Price (CDN$ per bbl)	59.94	55.50	73.33	65.79
Benchmark Prices				
WTI Oil (US$ per bbl) (1)	73.15	97.44	93.00	97.97
WCS Oil (US$ per bbl) (2)	67.45	69.62	73.60	72.78
Heavy Oil Differential (3)	8%	29%	21%	26%
CAD/USD Average Exchange Rate	1.14	1.05	1.10	1.03

Notes:
(1) WTI refers to the arithmetic average based on NYMEX prompt month WTI (West Texas Intermediate)
(2) WSC refers to the average posting price for the benchmark WCS (Western Canada Select) heavy oil
(3) Heavy oil differential refers to the WCS discount to WTI

Revenue for the year ended December 31, 2014 was $10 million, compared to $8.8 million for the year ended December 31, 2013. Revenue for the three months ended December 31, 2014 was $1.7 million, compared to $2.2 million for the quarter ended December 31, 2013. Revenue increased throughout the year due to the higher price of oil in the second and third quarter of 2014 partly due to the lower Canadian dollar and lower differential. Production was down in Q4 2014 to 313 from 428 for Q4 2013. Q4 2014 production was less than Q4 2013 production due to the lower prices and the shutting in of the wells. Production increased slightly from 365 bbls per day in 2013 to 374 bbls per day in 2014. Most of the increase in production is due to the recompletion of suspended wells in Q1 and Q2 of 2014. Included in the Q4 2014 oil revenue is $94,000 of skim oil recovered from the water disposal, $8,000 for Q4 2013. Included in the year ended December 31, 2014 oil revenue is $411,624 of skim oil recovered from the water disposal, compared to $9,835 for the same period in 2013.

Royalties

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
Heavy Oil Royalties ($000s)	298	432	1,726	1,275
Total Royalties ($ per bbl)	10.35	10.97	12.64	9.58
Percent of Oil Revenue	17%	19%	15%	14%

Royalties for the year ended December 31, 2014 increased to $1.7 million, compared to $1.3 million for the year ended December 31, 2013. Royalties increased in 2014 mostly due to the increase in price for oil in Q2 and Q3. Royalties for the three months ended December 31, 2014 decreased to $.3 million, compared to $0.4 million for the three months ended December 31, 2013. This decrease is due to the low prices of oil in Q4 2014. Royalties per bbl for the year ended December 31, 2014 increased to $12.64 from $9.58 for the same period in 2013. This is mainly due to the higher commodity prices for oil in 2014 compared to 2013. Royalties per bbl for the three months ended December 31, 2014 decreased to $10.35 from $10.97 for the same period in 2013. Total royalties as a percentage of revenue for the year ended December 31, 2014 were 15% of oil revenue, as compared to 14% for the same period in 2013. Total royalties as a percentage of revenue for the three months ended December 31, 2014 were 17% of oil revenue, as compared to 19% for the same period in 2013. In Q4 2014 $11,000 of royalties is on skim oil from water disposals, $0 of royalties were from skim oil in Q4 2013. For the year ended 2014 $47,833 of royalties is on skim oil from the water disposals, $0 of royalties were from skim oil for the same period in 2013.

Production and Transportation Expenses

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
Production Expense ($000s)	1,217	1,577	5,365	4,640
Transportation Expense ($000s)	68	138	464	450
Total Production & Transportation Expense ($000s)	1,285	1,715	5,829	5,090
Production Expense ($ per bbl)	42.32	40.07	39.30	34.84
Transportation Expense ($ per bbl)	2.36	3.51	3.40	3.38
Total Production & Transportation Expense ($ per bbl)	44.68	43.58	42.70	38.22

Production expense for the year ended December 31, 2014 was $5.4 million, compared to $4.6 million for the year ended December 31, 2013. This increase is mostly due to an increase in total fluid production related to higher water cut wells. Production expense for the three months ended December 31, 2014 was $1.2 million, compared to $1.6 million for the three months ended December 31, 2013. This decrease is due to the wells being temporarily shut in until price recovers. Production expense of $78 thousand was attributed to the water disposals for Q4 2014, compared to $24 thousand for the same period in 2013. Production expense of $265 thousand was attributed to the water disposals for the year ended December 31, 2014, compared to $27 thousand for the same period in 2013.

Production expense per bbl for the year ended December 31, 2014 was $39.30, compared to $34.84 for the year ended December 31, 2013. Production expense per bbl for the three months ended December 31, 2014 was $42.32, compared to $40.07 for the three months ended December 31, 2013. This increase was mainly due to higher than normal propane costs and increased water production through the first half of 2014.

Transportation expense for the year ended December 31, 2014 was $464,000, compared to $450,000 for the year ended December 31, 2013. This slight increase is due to the longer wait times at the treating facilities due to capacity issue arising from the restrictions of rail transport in the second and third quarter of 2014. Transportation expense for the three months ended December 31, 2014 was $68,000, compared to $138,000 for the year ended December 31, 2013. This decrease is due to the wells being temporarily shut in until price recovers. Transportation expense of $5 thousand was attributed to the water disposals for Q4 2014, compared to $1 for the same period in 2013. Transportation expense of $13 thousand was attributed to the water disposals for the year ended December 31, 2014, compared to $1 thousand for the same period in 2013. Transportation expense per bbl for the year ended December 31, 2014 was $3.40, compared to $3.38 for the year ended December 31, 2013. Transportation costs remained relatively stable year over year. Transportation expense per bbl for the three months ended December 31, 2014 was $2.36, compared to $3.51 for the year ended December 31, 2013.

Operating Netback

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
Sales Volume (bbls/day)	313	428	374	365
Oil Revenue Price ($ per bbl)	61.32	56.46	74.69	66.07
Water Disposal Revenue Price ($ per bbl)	3.26	0.27	2.45	0.08
Less: Royalties ($ per bbl)	(10.36)	(10.98)	(12.64)	(9.58)
Production Expense ($ per bbl)	(42.32)	(40.07)	(39.30)	(34.84)
Transportation Expense ($ per bbl)	(2.36)	(3.51)	(3.40)	(3.38)
Oil Operating Netback ($ per bbl)	9.64	2.17	21.80	18.36

Operating netback for the year ended December 31, 2014 was $21.80 per bbl, compared to $18.36 for the year ended December 31, 2013. Operating netback for the three months ended December 31, 2014 was $9.63 per bbl, compared to $2.17 for the three months ended December 31, 2013. Total revenue price for the year ended December 31, 2015 increased from $66.15 per bbl to $77.14 per bbl for the same period in 2013 offset by an increase in royalties from $9.58 per bbl to $12.64 per bbl resulting largely from changes in the mix of producing wells related to the

acquisition of certain wells in the Lloydminster area, and an increase of production expense from $34.84 per bbl to $39.30 per bbl due to an increase in the cost of propane.

General and Administrative Expenses

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
G & A Expense ($000s)	200	235	810	807
G & A Recoveries ($000s)	(20)	(3)	(89)	(101)
Total G & A Expense ($000s)	180	232	721	706
Total G & A Expense ($ per bbl)	6.27	5.89	5.21	5.31

General and administrative expense, net of recoveries, was $721,000 or $5.21 per bbl for the year ended December 31, 2014 compared to $706,000 or $5.31 per bbl for the year ended December 31, 2013. General and administrative expense, net of recoveries, was $180,000 or $6.27 per bbl for the three months ended December 31, 2014 compared to $232,000 or $5.89 per bbl for the year ended December 31, 2013. General and administrative expense remained relatively stable from 2013 to 2014 as no material changes occurred.

Depletion and Depreciation

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
Depletion ($000s)	478	655	2,293	2,343
Depletion ($ per bbl)	16.62	16.64	16.80	17.59

Depletion for the year ended December 31, 2014 was $2.3 million which is consistent with the $2.3 million for the year ended December 31, 2013. Depletion for the three months ended December 31, 2014 was $0.5 million compared to the $0.7 million for the year ended December 31, 2013. Depletion and depreciation per bbl was $16.80 for the year ended December 31, 2014, as compared to $17.59 for the year ended December 31, 2013. Depletion and depreciation per bbl was $16.62 for the three months ended December 31, 2014, as compared to $16.64 for the three months ended December 31, 2013. Depreciation was slightly lower due to the slightly lower production and relatively stable reserve value.

Finance Expense

	Three months ended December 31		Twelve months ended December 31	
	2014	**2013**	**2014**	**2013**
($000s)				
Distributions Paid to Preferred Unit Holders	858	831	3,364	3,258
Accretion of Decommissioning Provision	32	6	126	23
Preferred Unit Redemptions (Excess Carry Value to Redemption Cost - Preferred Units)	(6)	(2)	(7)	(10)
Bank Interest Income	(19)	(12)	(39)	(97)
Interest on Note Receivable	–	–	(4)	–
Total Finance Expense	865	823	3,440	3,174

Finance expense for the year ended December 31, 2014 was $3.4 million, as compared to $3.2 million for the year ended December 31, 2013. This increase was mostly due to the slightly higher distributions paid out in cash and higher accretion expense due to an adjustment in how decommissioning costs were calculated. Finance expense for the three months ended December 31, 2014 was relatively flat at $0.87 million, as compared to $0.82 million for the year ended December 31, 2013.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31		Twelve months ended December 31	
($000s)	**2014**	**2013**	**2014**	**2013**
Net Income (Loss)	(1,846)	(1,557)	(3,937)	(3,714)

Net and comprehensive income was a net loss of $3.9 million, compared to a net loss of $3.7 million for the year ended December 31, 2013. Net and comprehensive income for the quarter ended December 31, 2014 was a net loss of $1.9 million, compared to a net loss of $1.6 million for the quarter ended December 31, 2013. This increase in loss was mostly due to a write down of undeveloped land in the amount of $615,000.

Capital Expenditures

Capital expenditures are summarized as follows:

	Three months ended December 31		Twelve months ended December 31	
($000s)	**2014**	**2013**	**2014**	**2013**
Additions: Land	(604)	103	(519)	6,941
Seismic	–	7	–	9
Drilling and Completion	232	367	1,135	1,132
Equipping	35	199	594	2,609
Decommissioning Provision	349	239	1,382	3,629
Total Capital Additions Expenditure	12	915	2,591	14,320

At the end of 2014 Petrocapita decided to substantially reduce its capital spending on drilling and completion of oil wells and focus primarily on developing produced salt water disposal sites.

An impairment loss of $615,000 was recognized for the year ended December 31, 2014, relating to Petrocapita's undeveloped land in Saskatchewan based on management's assessment of fair value based on current market rates for undeveloped land sales. At December 31, 2014, $1,070,000 of Saskatchewan land is expected to be recoverable.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Trust prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures.

The Trust's accounts payable and accrued liabilities are aged as follows:

	2014	**2013**
0 - 30 days	$ 1,194,647	$ 1,692,032
31 to 60 days	135,191	–
61 to 90 days	28,315	–
Greater than 90 days	16,774	–
Total accounts payable and accrued liabilities	$ 1,374,927	$ 1,692,032

The Trust expects to satisfy its obligations under accounts payable and accrued liabilities within the next year. The Trust expects to only redeem the Preferred Units if demanded by the holder in accordance with the terms of the Declaration of Trust.

Market risk – Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk – The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider

instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the years ended December 31, 2014 and 2013 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Capital management – The Trust's capital is defined to be unitholders' equity and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments. The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis:

	2014	**2013**
Cash	$ 2,598,148	$ 4,569,186
Accounts receivable	800,052	749,503
Note receivable	21,790	36,133
Prepaid expenses and deposits	99,712	85,564
Accounts payable and accrued liabilities	(1,374,927)	(1,692,033)
Current portion of Preferred Units	(1,572,195)	–
Working capital	$ 572,580	$ 3,748,353

The Trust is not subject to any externally imposed capital requirements other than the redemption feature of the Preferred Units and Trust Units. The Trust's capital management objectives have not changed during the years ended December 31, 2014 or 2013.

Units of the Trust

Beneficial interests in the Trust are represented and constituted by two classes of Units – being common trust units of the Trust ("**Trust Units**") and preferred trust units of the Trust ("**Preferred Units**") – of which an unlimited number of each class are authorized and may be issued. The rights, privileges, restrictions and conditions attached to the Trust Units and the Preferred Units are set out in the Declaration of Trust.

See "*Declaration of Trust*" and "*Securities of the Trust*" in the attached prospectus of which this MD&A forms a part.

Trust Units and Preferred Units, as well as any other securities of the Trust, may be created, issued, sold and delivered at the times, to the persons, for the consideration, and otherwise on the terms and conditions determined by the Trustees in their absolute discretion.

The Trustees may, in their discretion, at any time and from time to time, subdivide or consolidate each or either class of Units outstanding.

Subject to any discounts that the Trustees may allow as consideration for agreeing to subscribe for Units, Units are only to be issued when fully paid, and they are not subject to future calls or assessment; provided, however, that Units issued under an offering may be issued for a consideration payable in instalments and the Trust may take security over any such Units for unpaid instalments. The consideration for any Unit issued by the Trust shall be paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit has been issued for money; provided that property may include a promissory note.

There are no pre-emptive rights attaching to either the Trust Units or the Preferred Units as a class.

Conversion of Preferred Units to Trust Units

The Preferred Units are convertible to Trust Units, at the option of the Trust, on not less than 30 days' written notice, at a conversion ratio determined according to the formula set forth in the Declaration of Trust.

On May 22, 2015, the Trust issued a notice of conversion to the holders of the outstanding Preferred Units pursuant to which, in accordance with the Declaration of Trust, all outstanding Preferred Units were converted to Trust Units effective June 21, 2015 on the basis of approximately 32.6 Trust Units for every one (1) Preferred Unit. As a consequence of that conversion, there are no Preferred Units left outstanding, and the former holders of Preferred Units are deemed to be holders of Trust Units and shall not be entitled to any rights as holders of Preferred Units.

Throughout 2014, however, there were Preferred Units outstanding.

Preferred Units

Each holder of Preferred Units is entitled to one vote per unit but may only vote on matters related to the rights of the holders of Preferred Units. Such unitholders shall be entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees of the Trust. If distributions in excess of $0.1025 are declared in any year, the holders of Preferred Units will receive 10% of the excess distribution up to a maximum of $0.0175 per unit. Subject to certain limitations, holders of Preferred Units are entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All Preferred Units are redeemable on demand by the unitholder or the Trust. If the redemption is demanded by the Trust the redemption amount is the original capital plus cumulative dividends. If the redemption is demanded by the unit holder the redemption price is determined as 90% of the market value of the unit. The market value is determined solely by the Administrator. Redemptions are limited to $7,500 per month, and any redemption requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust may also convert the Preferred Unit to a Trust Unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units are considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units are bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative is the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument is measured at the redemption amount that is payable at the end of the reporting period if the holder exercised its right to redeem the unit.

A distribution re-investment program ("**DRIP**") was initiated in September of 2011 and the first re- investment of distributions took place on September 30, 2011. A total of $3.4 million was paid out in distributions in 2014 with $1.2 million being reinvested in Preferred Units for the year ended December 31, 2014. Distributions of $3.3 million with $1.1 million being re invested for the year ended December 31, 2013.

During the year 2014, the Trust redeemed 68,294 Preferred Units at a price $0.90 per unit.

109,000 Preferred Units were redeemed for the same period in 2013. The excess of the carrying value over the redemption price was recorded as a component of finance expenses. With the exception of the DRIP, no new units were issued in the year ending December 31, 2014. There were 33,537,971 Preferred Units outstanding as at December 31, 2014. There were 32,415,452 Preferred Units outstanding as at December 31, 2013.

Trust Units

Each holder of Trust Units is entitled to one vote per unit and shall be entitled to receive noncumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. There were 5,843,357 Trust Units outstanding as at December 31, 2014. The same number was outstanding as at December 31, 2013.

Use of Estimates and Judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future petroleum and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

Amounts recorded for decommissioning provisions and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates.

The allocation of proceeds on the issuance of Preferred Units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the Preferred Units.

The valuation of accounts receivable and note receivable are based on management's best estimate of collectability and the provision for doubtful accounts.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust operates are subject to change.

By their nature, these estimates are subject to measurement uncertainty.

Changes in Accounting Policies

The following pronouncements issued by the IASB and interpretations published by International Financial Reporting Interpretations Committee (IFRIC) became effective for annual periods beginning on or after January 1, 2014:

IAS 32, Financial Instruments: Presentation, has been amended to clarify certain requirements for offsetting financial assets and liabilities. The amendment addresses the meaning and application of the concepts of legally enforceable right of set-off and simultaneous realization and settlement. This amendment had no impact on the Trust's results or financial position.

IAS 36, Impairment of Assets, has been amended to require disclosure of the recoverable amount of an asset (including goodwill) or a cash generating unit when an impairment loss has been recognized or reversed in the period. When the recoverable amount is based on fair value less costs to sell, the valuation techniques and key assumptions must also be disclosed. The amendment has been reflected in all notes where an impairment loss has been recognized.

IFRIC 21, Levies, on the accounting for levies imposed by governments clarifies the obligating event that gives rise to a liability to pay a levy. The adoption of this IFRIC had no impact on the Trust's results or financial position.

MANAGEMENT'S DISCUSSION AND ANALYSIS – 2013

The following Management's Discussion and Analysis ("**MD&A**") is a review of the operations and financial position for the year ended December 31, 2013 for Petrocapita Income Trust (the "**Trust**" and, together with its subsidiaries, "**Petrocapita**") and should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2013 and 2012, together with the notes thereto (the "**financial statements**"). All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentages and per share amounts or as otherwise noted. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

Forward Looking Statements

Reference is made to the section entitled "*Forward-Looking Statements*" in the attached prospectus of which this MD&A forms a part, and all cautionary statements made therein apply to this MD&A.

General Business Description

Petrocapita Income Trust was formed pursuant to a Declaration of Trust dated January 22, 2010. The Trust has been established with the objective of investing indirectly in a portfolio of petroleum producing properties through its acquisition of debt and equity securities issued by Petrocapita Oil and Gas L.P. (the "**Partnership**"). The Partnership was formed solely to carry on the business of investing in, conducting, engaging in, or otherwise being involved in one or more of the acquisition, exploration, exploitation, development, optimization, enhancement, production and processing of petroleum and natural gas and related products, and such other business activities as are in any way related, ancillary or incidental thereto.

Petrocapita GP I Ltd. is the general partner of the Partnership and the administrator of the Trust (the "**General Partner**", or the "**Administrator**", as the context requires).

See "*The Trust and its Subsidiaries*", "*Declaration of Trust*", "*Limited Partnership Agreement*" and "*Administration Agreement*" in the attached prospectus of which this MD&A forms a part.

The beneficiaries of the unincorporated Trust are the unitholders. The consolidated financial statements present only the assets, liabilities, and results of operations of the Trust and its subsidiaries.

Under the *Income Tax Act* (Canada), the Trust is currently subject to income taxes only on income that is not distributed or distributable to the unit holders. That will change if the Trust becomes a "specified investment flow-through" (SIFT) trust for purposes of the *Income Tax Act* (Canada). See "*Taxation of Specified Investment Flow-Through Trusts*" in the attached prospectus of which this MD&A forms a part. The Trust, to date, has no undistributed income. The income tax consequences of the Trust and ultimately those of the Partnership are currently deemed to be those of the unitholders individually. Consequently no income tax provision or recovery, nor income tax asset or liability, is reflected in the consolidated financial statements. The consolidated financial statements of the Trust comprise the Trust and its two subsidiaries, the Partnership and the General Partner.

The Partnership's principal activity is the acquisition of, exploration for and the development and production of heavy oil properties in the Manville formation around the Lloydminster area in Alberta and Saskatchewan.

Non-IFRS Measures

In addition to using financial measures prescribed by IFRS, references are made in this MD&A to "Adjusted EBITDA", "operating netback", "operating cash flow", "net debt" and "funds flow from operations", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the financial statements of the Trust. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities. Management uses such terms in the evaluation of the Trust's operating and financial performance and to provide Trust unitholders with a measurement of the Trust's efficiency and its ability to generate the cash necessary to fund its capital expenditures, repay debt or pay distributions. For the meaning of

these terms as used by Management, see "*Notice to Investors – Non-IFRS Measures*" at pages 10 and 11 of the attached prospectus of which this MD&A forms a part.

The following table provides a reconciliation of net income (loss) to Adjusted EBITDA.

	Three months ended December 31		**Twelve months ended December 31**	
($000s)	**2013**	**2012**	**2013**	**2012**
EBITDA				
Net Income (Loss)	(1,557)	(1,380)	(3,714)	(4,375)
Distributions to Shareholders	831	784	3,258	2,368
Unit Issue Costs	–	261	–	1,838
Decommissioning Obligations Accretion	6	5	23	18
Depletion and Depreciation	655	196	2,343	846
Bank Interest Income	(12)	(39)	(97)	(61)
Interest on Note Receivable	–	(1)	–	(2)
Preferred Unit Redemptions (Excess Carry Value to Redemption Cost - Preferred Units)	(2)	(2)	(10)	(1)
Gain on Sale of Assets	(65)	–	(65)	–
Impairment of Assets	–	–	–	–
Adjusted EBITDA	**(145)**	**(177)**	**1,738**	**631**

A reconciliation of the cash flow from operating activities and funds flow from operations is as follows:

	Three months ended December 31		**Twelve months ended December 31**	
($000s)	**2013**	**2012**	**2013**	**2012**
Cash Flow from Operations - IFRS	425	(696)	2,137	1,156
Changes in Non-cash Operating Working Capital	(558)	558	(302)	(464)
Bank Interest Income	(12)	(39)	(97)	(61)
Funds Flow From Operations	(145)	(177)	1,738	631

The forward-looking statements included in this document are expressly qualified by the cautionary statements made in the attached prospectus and are made as of the date of this document. The Trust does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

2013 Overview

In 2013 Petrocapita closed two asset acquisitions. See "*General Development of Business – 2013*" in the attached prospectus of which this MD&A forms a part. The results of both acquisitions are included in the 2013 financial results of the Trust.

Petrocapita initiated a produced water disposal program in 2013 to help lower its operating and transportation costs and create additional cash flow by disposing of third party produced water and recovering skim oil. Petrocapita's first water disposal well initiated operations in November 2013. Results of operations of this first water disposal well are included in the 2013 financial statements.

Selected Annual Financial Information

	Year ended December 31		
($000s)	**2013**	**2012**	**2011**
Total Revenue [1]	8,772	4,406	1,748
Funds Flow From Operations [2]	1,738	631	431
Net Income (loss)	(3,714)	(4,375)	(1,102)
Operating Netback ($ per bbl)	18.36	17.31	33.04
Total Assets	32,988	31,274	16,881
Total Liabilities	35,422	30,091	13,229
Net Debt [3]	(3,748)	(14,805)	(6,860)

Selected Quarterly Information

The following table highlights Petrocapita's performance for each of the eight quarters ended December 31, 2013:

($000s)	**Q4 2013**	**Q3 2013**	**Q2 2013**	**Q1 2013**	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**
Total Oil Sales (bbls)	39,360	44,009	34,304	15,500	16,305	16,648	18,393	17,096
Total Oil Sales (bbls/day)	428	484	373	172	177	183	200	188
Average Realized Price ($ per bbl)	56.73	85.71	48.27	74.06	58.20	71.84	50.40	78.03
Total Revenue	2,233	3,772	1,656	1,148	949	1,196	927	1,334
Operating Netback ($ per bbl)	2.20	35.38	20.78	5.72	4.34	31.59	10.29	23.32
Funds Flow From Operations ($ per bbl)	(3.69)	31.28	16.57	(3.95)	(10.88)	25.33	1.17	21.29
Net Income (loss)	(1,557)	(166)	(801)	(1,190)	(1,380)	(1,286)	(1,006)	(702)
Total Assets	32,988	33,621	33,338	30,831	31,274	28,600	24,080	19,736
Capital Expenditures	676	640	2,465	6,909	812	1,583	2,791	2,399

Notes:
(1) Includes oil revenue, skim oil revenue water disposal revenue and oil royalty revenue
(2) See "*Notice to Investors – Non-IFRS Measures*" in the prospectus (pp. 10-11)
(3) Net Debt equals current liabilities less current assets

2013 Operations

Revenue and Production

	Three months ended December 31		Twelve months ended December 31	
	2013	**2012**	**2013**	**2012**
Heavy Oil Revenue ($000s)	2,184	949	8,761	4,406
Heavy Oil Production (bbls/day)	428	177	365	187
Average Realized Price ($ per bbl)	55.50	58.21	65.79	64.37
Benchmark Prices				
WTI Oil (US$ per bbl)[1]	97.44	88.18	97.97	94.19
WCS Oil (US$ per bbl)[2]	69.62	70.50	72.78	73.18
Heavy Oil Differential[3]	29%	20%	26%	22%
CAD/USD Average Exchange Rate	1.05	0.99	1.03	1.00

Notes:
(1) WTI refers to the arithmetic average based on NYMEX prompt month WTI (West Texas Intermediate)
(2) WSC refers to the average posting price for the benchmark WCS (Western Canada Select) heavy oil
(3) Heavy oil differential refers to the WCS discount to WTI

Revenue for the year ended December 31, 2013 was $8.8 million, compared to $4.4 million for the year ended December 31, 2012. Revenue for the three months ending December 31, 2013 was $2.2 million compared to $0.9 million for the three months ending 2012. Production also increased substantially from 187 bbls/day in 2012 to 365 bbls/day in 2013 and a similarly large quarter to quarter increase from 177 bbls/day at the three months ending December 31, 2013 to 428 bbls/day for the same three months ending December 31, 2012. Most of this increase in production and revenue is due to the two asset acquisitions made in March of 2013. Included in the 2013 oil revenue is $8,000 of skim oil recovered from the water disposal. Skim oil production for 2013 was 0.5 bbls/day.

Royalties

	Three months ended December 31		**Twelve months ended December 31**	
	2013	**2012**	**2013**	**2012**
Heavy Oil Royalties ($000s)	432	102	1,275	651
Total Royalties ($ per bbl)	10.98	6.26	9.58	9.52
Percent of Oil Revenue	11%	20%	15%	15%

Royalties for the year ended December 31, 2013 increased to $1.3 million, compared to $0.7 million for the year ended December 31, 2012. Royalties per quarter increased from $102,000 for the three months ended December 31, 2013 compared to $432,000 for the same three months ended December 31, 2012. Royalties increased in 2013 mostly due to the two property acquisitions, as production increased by 100%. Royalties per bbl for the year ended December 31, 2013 was 9.58 which was relatively flat in 2013 compared to 9.52 in 2012. Total royalties per bbl for the three months ended December 31, 2013 were 10.98 compared to 6.26 for the three months ended December 31, 2012. Total royalties as a percentage of revenue for the year ended December 31, 2013 were 15 % of oil revenue, which is unchanged from the 15% for the same period in 2012. Royalties as a percentage of revenue decreased for the three months ended December 31, 2013 to 11% from 20% for the three months ending December 31, 2012. Royalties per bbl increased in Q4 2013 due to an increase in crown royalties. Crown royalty rates are a function of production; when well production increases, crown royalty rates for that well increase. Percent of revenue decreased as the wells acquired in Q2 of 2013 had a lower royalty rate attached to them.

Production and Transportation Expenses

	Three months ended December 31		**Twelve months ended December 31**	
	2013	**2012**	**2013**	**2012**
Production Expense ($000s)	1,577	731	4,640	2,379
Transportation Expense($000s)	138	45	450	190
Total Production & Transportation Expense ($000s)	1,715	776	5,090	2,569
Production Expense ($ per bbl)	40.07	44.83	34.84	34.76
Transportation Expense ($ per bbl)	3.51	2.76	3.38	2.78
Total Production & Transportation Expense ($ per bbl)	43.58	47.59	38.22	37.54

Production expense for the year ended December 31, 2013 was $4.6 million, compared to $2.4 million for the year ended December 31, 2012. Production expense for the three months ended December 31, 2013 was $1.6 million compared to $0.7 million for the three months ended December 31, 2012. This increase is mostly due to the increase in production due to the acquisition. Production costs of $23,000 for the year ended December 31, 2013 were attributed to the water disposal initiated in November of 2013.

Production expense per bbl for the year ended December 31, 2013 was $34.84, compared to $34.76 for the year ended December 31, 2012. Production expense per bbl for the three months ended December 31, 2013 was $40.07 down from $44.83 for the three months ending December 31, 2012. This decrease in production expense was related to the acquired wells having a lower production costs than Petrocapita's original wells.

Transportation expense for the year ended December 31, 2013 was $450,000, compared to $190,000 for the year ended December 31, 2013. Transportation expense for the three months ended December 31, 2013 was $138,000 compared to $45,000 for the three months ended December 31, 2012. This increase is mostly due to the acquisition but also due to longer distances travelled for a better price and increased wait times at the sales point in the third quarter of 2013.

Transportation expense per bbl for the year ended December 31, 2013 was $3.38, compared to $2.78 for the year ended December 31, 2012. Transportation expense per bbl for the three months ended December 31, 2013 was $3.51 compared to $2.76 for the three months ended December 31, 2012 Increase was due to further distance travelled for better pricing and for longer wait times during the third quarter of 2013.

Operating Netback

	Three months ended December 31		**Twelve months ended December 31**	
($ per bbl Except for % and Volume)	**2013**	**2012**	**2013**	**2012**
Sales Volume (bbls/day)	428	177	365	187
Oil Revenue Price ($ per bbl)	56.46	58.20	66.07	64.37
Water disposal Revenue ($ per bbl)	0.27	–	0.08	–
Less: Royalties ($ per bbl)	(10.98)	(6.26)	(9.58)	(9.52)
Production Expense ($ per bbl)	(40.07)	(44.83)	(34.84)	(34.76)
Transportation Expense ($ per bbl)	(3.51)	(2.76)	(3.38)	(2.78)
Operating Netback ($ per bbl)	2.17	4.35	18.36	17.31

Sales volume doubled from 187 bbls/d for the twelve months ended December 31, 2012 to 365 bbls/d for the twelve months ended December 31, 2013. For the three months ended December 31, 2013 sales volume was 428 bbls/d compared to 177 bbls/d for the three months ended December 31, 2012. The increase is due to the two asset acquisitions made in the second quarter of 2013. Total revenue price increased from $64.37 per bbl to $66.15 per bbl for the years ended December 31, 2012 and 2013 respectively. Total revenue price decreased from $58.20 for the three months ended December 31, 2012 to $56.73 for the three months ended December 31, 2013. Royalties increased slightly to $9.58 per bbl from $9.52 per bbl in the previous year. Production expense remained relatively flat, $34.84 per bbl for the year ended December 31, 2013 and $34.76 per bbl for the year ended December 31, 2012. Production expense per bbl for the three months ended December 31, 2013 was $40.07 down from $44.83 for the three months ending December 31, 2012. Transportation expense for the year ended December 31, 2013 was $3.38 per bbl compared to $2.78 per bbl for the year ended December 31, 2012. Transportation expense per bbl for the three months ended December 31, 2013 was $3.51 compared to $2.76 for the three months ended December 31, 2012. The increase was due to the longer distance to get oil to sales point for the new wells acquired in 2013. Operating netback for the year ended December 31, 2013 was $18.36 as compared to $17.31 for the year ended December 31, 2012. This increase is due to the increase in oil price and increase in oil production on a yearly basis. Operating netback per bbl for the three months ended December 31, 2013 was $2.17 down from $4.35 for the three months ending December 31, 2012. The decrease in the last quarter of 2013 from 2012 was due to the lower price of oil received and the higher cost of royalties and production expense per bbl.

General and Administrative Expenses

	Three months ended December 31		**Twelve months ended December 31**	
	2013	**2012**	**2013**	**2012**
G & A Expense ($000s)	235	249	807	560
G & A Recoveries ($000s)	(3)	(1)	(101)	(5)
Total G & A Expense ($000s)	232	248	706	555
Total G & A Expense ($ per bbl)	5.89	15.22	5.31	8.10

General and administrative expense, net of recoveries, was $706,000 or $5.31 per bbl for the year ended December 31, 2013 compared to $555,000 or $8.10 per bbl for the year ended December 31, 2012. General and administrative expense, net of recoveries, was $232,000 or $5.89 per bbl for the three months ended December 31, 2013 compared

to $248,000 or $15.22 per bbl for the three months ended December 31, 2012. On a quarterly and per bbl basis, G & A has decreased, as production doubled due to the two acquisitions but no new staff was added.

Depletion and Depreciation

	Three months ended December 31		Twelve months ended December 31	
	2013	**2012**	**2013**	**2012**
Depletion & Depreciation ($000s)	655	196	2,343	846
Depletion & Depreciation ($ per bbl)	16.64	12.02	17.59	12.36

Depletion and depreciation for the year ended December 31, 2013 was $2.3 million compared to $0.8 million for the year ended December 31, 2012. Depletion and depreciation for the three months ended December 31, 2013 was $0.6 million compared to $ 0.2 million for the three months ended December 31, 2012. Depletion and depreciation per bbl was $17.59 for the year ended December 31, 2013, as compared to $12.36 for the year ended December 31, 2012. Depletion and depreciation per bbl was $16.64 for the three months ended December 31, 2013, as compared to $12.02 for the three months ended December 31, 2012.The increase in depletion and depreciation was due to the increase in reserves and production due to the acquisition. The increase in depletion and depreciation is greater than the per bbl increase due to the fact that actual production increase was greater than the increase in asset value.

Finance Expense

	Three months ended December 31		Twelve months ended December 31	
($000s)	**2013**	**2012**	**2013**	**2012**
Commissions on Issuance of Preferred Units	–	243	–	1,838
Distributions Paid to Preferred Unit Holders	831	784	3,258	2,368
Accretion of Decommissioning Provision	6	5	23	18
Preferred Unit Redemptions (Excess Carry Value to Redemption Cost - Preferred Units)	(2)	(3)	(10)	(3)
Bank Interest Income	(12)	(36)	(97)	(62)
Total Finance Expense	822	993	3,174	4,159

Finance expense for the year ended December 31, 2013 was $3.2 million, as compared to $4.2 million for the year ended December 31, 2012. Finance expense for the three months ended December 31, 2013 was $0.8 million, as compared to $1.0 million for the three months ended December 31, 2012. This decrease resulted from no new Preferred Units being issued in 2013, and therefore no commission costs were incurred in 2013. Adding to this decrease was the increase in bank interest income related to the extra cash on hand in 2013, a slight increase in Preferred Units being redeemed at 90% of carrying value, and partially offset by the slight increase in accretion due to the acquisition.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31		Twelve months ended December 31	
($000s)	**2013**	**2012**	**2013**	**2012**
Net Income (Loss)	(1,557)	(1,380)	(3,714)	(4,375)

Net loss and comprehensive loss was $3.7 million for the year ended December 31 2013, compared to a net loss of $4.4 million for the year ended December 31, 2012. Net loss and comprehensive loss was $1.6 million for the three months ended December 31, 2013, compared to a net loss of $1.4 million for the three months ended December 31, 2012. For the year 2013, revenues increased over expenses, financing costs decreased and there was a slight gain on sale of undeveloped exploration and evaluation assets.

Capital Expenditures

Capital expenditures are summarized as follows:

	Three months ended December 31		Twelve months ended December 31	
($000s)	**2013**	**2012**	**2013**	**2012**
Additions: Land	103	140	6,941	2,792
Seismic	7	31	9	58
Drilling and Completion	367	610	1,132	3,051
Equipping	199	31	2,609	1,683
Decommissioning Provision	239	26	3,629	282
Total Capital Additions Expenditure	915	838	14,320	7,867

During the year ended December 31, 2013, the Trust completed acquisitions of certain conventional producing oil and natural gas assets for $8,282,263 after closing adjustments. The December 31, 2013 financial statements incorporate the results of operations of the acquired properties from their closing dates of, March 22, 2013 and April 22, 2013, respectively, onwards.

Market risk – Market risk is the risk that changes in market prices, such as commodity prices, interest rates and foreign exchange rates will affect the Trust's net earnings or the value of financial instruments. The objective of the Trust is to manage and mitigate market risk exposures within acceptable limits, while maximizing returns.

Commodity price risk – The nature of the Trust's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Trust did not enter into any derivative financial contracts during the years ended December 31, 2013 and 2012 nor does it currently have any derivative financial contracts. The Trust does not utilize derivative financial instruments for speculative purposes.

Capital management – The Trust's capital is defined to be unitholders' equity and other debt. The Trust's objective in managing capital is to ensure it has sufficient working capital and access to sources of capital sufficient to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments. The Trust has entered into an agreement with the Partnership whereby the Trust will access capital markets to raise capital to be invested in the Limited Partnership rather than direct ownership by the Trust.

The Trust monitors its working capital closely, which is determined on the following basis:

	Twelve months ended December 31	
	2013	**2012**
Cash	$ 4,569,186	$ 14,582,815
Accounts receivable	749,503	244,893
Note receivable	36,133	43,633
Prepaid expenses and deposits	85,564	830,935
Accounts payable and accrued liabilities	(1,692,033)	(897,403)
Current portion of Preferred Units	–	–
Working capital	$ 3,748,343	$ 14,804,873

The Trust is not subject to any externally imposed capital expenditure requirements other than the redemption feature of the Preferred Units and Trust Units. The Trust's capital management objectives have not changed during the years ended December 31, 2013 or 2012.

Units of the Trust

Beneficial interests in the Trust are represented and constituted by two classes of Units – being common trust units of the Trust ("**Trust Units**") and preferred trust units of the Trust ("**Preferred Units**") – of which an unlimited number of each class are authorized and may be issued. The rights, privileges, restrictions and conditions attached to the Trust Units and the Preferred Units are set out in the Declaration of Trust.

See "*Declaration of Trust*" and "*Securities of the Trust*" in the attached prospectus of which this MD&A forms a part.

Trust Units and Preferred Units, as well as any other securities of the Trust, may be created, issued, sold and delivered at the times, to the persons, for the consideration, and otherwise on the terms and conditions determined by the Trustees in their absolute discretion.

The Trustees may, in their discretion, at any time and from time to time, subdivide or consolidate each or either class of Units outstanding.

Subject to any discounts that the Trustees may allow as consideration for agreeing to subscribe for Units, Units are only to be issued when fully paid, and they are not subject to future calls or assessment; provided, however, that Units issued under an offering may be issued for a consideration payable in instalments and the Trust may take security over any such Units for unpaid instalments. The consideration for any Unit issued by the Trust shall be paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit has been issued for money; provided that property may include a promissory note.

There are no pre-emptive rights attaching to either the Trust Units or the Preferred Units as a class.

Conversion of Preferred Units to Trust Units

The Preferred Units are convertible to Trust Units, at the option of the Trust, on not less than 30 days' written notice, at a conversion ratio determined according to the formula set forth in the Declaration of Trust.

On May 22, 2015, the Trust issued a notice of conversion to the holders of the outstanding Preferred Units pursuant to which, in accordance with the Declaration of Trust, all outstanding Preferred Units were converted to Trust Units effective June 21, 2015 on the basis of approximately 32.6 Trust Units for every one (1) Preferred Unit. As a consequence of that conversion, there are no Preferred Units left outstanding, and the former holders of Preferred Units are deemed to be holders of Trust Units and shall not be entitled to any rights as holders of Preferred Units.

Throughout 2013, however, there were Preferred Units outstanding.

Preferred Units

Each holder of Preferred Units is entitled to one vote per unit but may only vote on matters related to the rights of the holders of Preferred Units. Such unitholders shall be entitled to receive cumulative distributions of $0.1025 per unit per annum if, and when, declared by the trustees of the Trust. If distributions in excess of $0.1025 are declared in any year, the holders of Preferred Units will receive 10% of the excess distribution up to a maximum of $0.0175 per unit. Subject to certain limitations, holders of Preferred Units are entitled to participate in distributions made, if any, in excess of the aforementioned cumulative distributions. All Preferred Units are redeemable on demand by the unitholder or the Trust. If the redemption is demanded by the Trust the redemption amount is the original capital plus cumulative dividends. If the redemption is demanded by the unit holder the redemption price is determined as 90% of the market value of the unit. The market value is determined solely by the Administrator. Redemptions are limited to $7,500 per month, and any redemption requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. The Trust may also convert the Preferred Unit to a Trust Unit at the discretion of the Trustees or automatically in the event of a plan of arrangement, amalgamation, reorganization or other business combination.

The Preferred Units are considered to be a hybrid instrument with an embedded derivative due to their redemption features. Upon initial issuance, the units are bifurcated into their debt (90% based on the redemption value) and equity components. The embedded derivative is the holder's option to redeem the units based on fair value at the time of the redemption. As a result of the separate accounting for the embedded derivative, the combined instrument is measured at the redemption amount that is payable at the end of the reporting period if the holder exercised its right to redeem the unit.

A distribution re-investment program ("**DRIP**") was initiated in September of 2011 and the first re- investment of distributions took place on September 30, 2011. A total of $3.3 million was paid out in distributions in 2013 with $1.1 million being reinvested in Preferred Units for the year ended December 31, 2013. Distributions of $2.4 million were paid out with $0.7 million being re-invested during the year ended December 31, 2012.

During the year 2013, the Trust redeemed 109,000 Preferred Units at a price of $0.90 per unit. 25,000 Preferred Units were redeemed at $0.90 per unit during the year ended December 31, 2012. The excess of the carrying value over the redemption price was recorded as a component of finance expenses. During the year ended December 31, 2012 proceeds of $18,346,615 were received from the issuance of 18,346,615 units. With the exception of the DRIP, no new units were issued in the year ending December 31, 2013. There were 32,415,452 Preferred Units outstanding as at December 31, 2013. There were 31,433,667 Preferred Units outstanding as at December 31, 2012.

Trust Units

Each holder of Trust Units is entitled to one vote per unit and shall be entitled to receive noncumulative distributions if, and when, declared by the trustees. All units are redeemable on demand by the unit holder with the redemption price determined as 90% of the market value of the unit. The market value is determined solely by the Administrator of the Trust. Redemptions are limited to $7,500 per month, and any redemptions requested in excess of that amount will be repaid through the issuance of a note payable or distribution of the property of the Trust. There were 5,843,357 Trust Units outstanding as at December 31, 2013.

Use of Estimates and Judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are as follows:

Amounts recorded for depletion and amounts used for impairment calculations relating to property and equipment are based on estimates of petroleum and natural gas reserves, including the estimates of future prices, costs, discount rates and the related future cash flows.

The valuation of exploration and evaluation assets depends on the discovery of economically recoverable reserves which in turn depends on future petroleum and natural gas prices, future capital expenditures, technical success and environmental and regulatory restrictions.

Amounts recorded for decommissioning provisions and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures and discount rates.

The allocation of proceeds on the issuance of Preferred Units between the debt and equity components is based on the estimate of the fair value of the debt component. In addition, the carrying value of the debt component is based on an estimate of the redemption value of the Preferred Units.

The valuation of accounts receivable and note receivable are based on management's best estimate of collectability and the provision for doubtful accounts.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust operates are subject to change.

By their nature, these estimates are subject to measurement uncertainty.

Changes in Accounting Policies

On January 1, 2013, the Trust adopted the following new standards and amendments which became effective for annual periods on or after January 1, 2013:

Consolidation

The Trust adopted IFRS 10, Consolidated Financial Statements, effective January 1, 2013. IFRS 10 requires consolidation of an investee only if the investor possesses power over the Investee has exposure or rights to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. The adoption of this standard had no impact on the amounts recorded in the Trust's financial statements.

Joint Arrangement

The Trust adopted IFRS 11, Joint Arrangements, effective January 1, 2013. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation to arrangements where sufficient rights and obligations are passed to the participants. The Trust re-assessed its classification of its joint arrangements and determined that there were no changes in the accounting applied to its joint arrangements.

Disclosure

The Trust adopted IFRS 12, Disclosure of Interests in Other Entities, effective January 1, 2013. IFRS 12 sets out the annual disclosure requirements for the Trust's interests in subsidiaries, joint arrangements and associates. The adoption of IFRS 12 had no impact on the amounts recognized in the Trust's financial statements or note disclosures. The Trust adopted amendments to IFRS 7 Financial Instruments: Disclosures effective January 1, 2013. IFRS 7 has been amended to require annual disclosure of information on rights to offset financial instruments and related arrangements. These amendments had no impact on the Trust's annual disclosures.

Fair Value Measurement

The Trust adopted IFRS 13, Fair Value Measurement, effective January 1, 2013. IFRS 13 improves consistency and reduces complexity by providing a precise definition of fair value and a single source of fair value measurement and disclosure requirements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard had no significant impact on the Trust's financial statements.

APPENDIX C

AUDIT COMMITTEE MANDATE

of

PETROCAPITA INCOME TRUST

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of trustees (the "**Board**") of Petrocapita Income Trust (the "**Trust**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures;

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. to assist the trustees of the Trust (the "**Trustees**") and the directors (the "**Administrator Directors**") of Petrocapita GP I Ltd. (the "**Administrator**"), the administrator of the Trust, as applicable, in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Trust and related matters;

2. to provide better communication between Trustees, Administrator Directors, management of the Administrator ("**Management**") and external auditors;

3. to enhance the external auditor's independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside Trustees and Administrator Directors by facilitating in depth discussions between Trustees on the Committee, Administrator Directors, Management and external auditors.

Membership of Committee

6. The Committee will be comprised of such number of Trustees as the Board may determine from time to time in accordance with all applicable securities laws and stock exchange rules (if any).

7. The Committee shall meet all applicable independence, financial literacy, financial expertise and other qualification criteria with which the Trust is required to comply under applicable securities laws and stock exchange rules (if any), and any applicable policies of the Board from time to time.

8. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

9. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

10. Satisfy itself on behalf of the Board with respect to the Trust's internal control systems.

11. Review the annual and interim financial statements of the Trust and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between Management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

12. Review the financial statements, prospectuses and other offering documents, MD&A, annual information forms ("**AIF**"), if applicable, and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of the Trust's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

13. Review and approve the disclosure of audit committee information required to be included in the AIF of the Trust, if applicable, prior to its filing with regulatory authorities.

14. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Administrator and Trust to determine the auditors' independence;
    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to the Trust or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

15. Review with external auditors (and internal auditor if one is appointed by the Trust or Administrator) their assessment of the internal controls of the Trust and its subsidiaries, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Trust and its subsidiaries.

16. Review risk management policies and procedures of the Trust and its subsidiaries (i.e. hedging, litigation and insurance).

17. Establish a procedure for:

    - the receipt, retention and treatment of complaints received by the Trust or its subsidiaries regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of the Trust and its subsidiaries of concerns regarding questionable accounting or auditing matters.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Trust. The Committee will also have the authority to investigate any financial activity of the Trust or its subsidiaries.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of the Trust without any further approval of the Board.

Meetings and Administrative Matters

18. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

19. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

20. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

21. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of the Administrator will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

22. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

23. The Committee may invite such officers, directors and employees of the Administrator and the Trust and its subsidiaries, as applicable, as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

24. Minutes of the Committee will be recorded and maintained and circulated to the Trustees who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

25. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Trust.

26. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Trustee. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as two (2) members remain on the Committee. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

27. Any issues arising from these meetings that bear on the relationship between the Board, the Administrator Directors and Management should be communicated to the Chairman of the Board by the Committee Chair.

APPENDIX D

FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data
by Chapman Petroleum Engineering Ltd. ("Chapman")
Qualified Reserves Evaluators

To the board of directors of Petrocapita Oil and Gas L.P. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) – M$			
			Audited	Evaluated	Reviewed	Total
Chapman	Reserve Evaluation July 17, 2015	Canada	–	40,569	–	40,569
Totals			–	40,569	–	40,569

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

[Original Signed By:]

Chapman, Calgary, Alberta, Canada, July 17, 2015

"*C. W. Chapman*"
C.W. Chapman, P. Eng.

APPENDIX E

FORM 51-101F3 – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Petrocapita GP I Ltd. (the "**Company**"), the administrator of Petrocapita Income Trust and the general partner of its subsidiary entity, Petrocapita Oil and Gas L.P. (collectively, "**Petrocapita**"), is responsible for the preparation and disclosure of information with respect to Petrocapita's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Petrocapita's reserves data. The report of the independent qualified reserves evaluator is presented above.

The board of directors of the Company has:

(a) reviewed Petrocapita's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors of the Company has reviewed Petrocapita's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATE: October 7, 2015

(signed) "*Alex Lemmens*"	(signed) "*Richard Mellis*"
President and Chief Executive Officer	Vice President, Land and Environment
(signed) "*Greg Marr*"	(signed) "*Ben Van Rootselaar*"
Director	Director

CERTIFICATE OF THE TRUST

Dated: October 26, 2015

This prospectus constitutes full, true and plain disclosure of all material facts relating to the securities previously issued by the issuer as required under the securities legislation of the Province of Alberta.

PETROCAPITA INCOME TRUST
By: Petrocapita GP I Ltd., as Administrator of the Trust

By: (signed) "*Alex Lemmens*"
President and Chief Executive Officer

By: (signed) "*Evelyn Studer*"
Vice President, Finance and Chief Financial Officer

On Behalf of the Board of Directors of Petrocapita GP I Ltd.,
the Administrator of Petrocapita Income Trust

By: (signed) "*Greg Marr*"
Director

By: (signed) "*Ben Van Rootselaar*"
Director

Part III – Item 14 (Capitalization) of CSE Form 2A

14. CAPITALIZATION

14.1 Prepare and file the following chart for each class of securities to be listed:

Issued Capital

	Number of Securities (non-diluted)	Number of Securities (fully-diluted)	% of Issued (non-diluted)	% of Issued (fully-diluted)
Public Float				
Total outstanding (A)	1,109,731,962	1,109,731,962 *(but see Item 14.2)*	100%	100% *(but see Item 14.2)*
Held by Related Persons or employees of the Issuer or Related Person of the Issuer, or by persons or companies who beneficially own or control, directly or indirectly, more than a 5% voting position in the Issuer (or who would beneficially own or control, directly or indirectly, more than a 5% voting position in the Issuer upon exercise or conversion of other securities held) (B)	742,924	742,924	0.0669%	0.0669%
Total Public Float (A-B)	1,108,989,038	1,108,989,038,	99.9331%	99.9331%
Freely-Tradeable Float				
Number of outstanding securities subject to resale restrictions, including restrictions imposed by pooling or other arrangements or in a shareholder agreement and securities held by control block holders (C)	0	0	0%	0%
Total Tradeable Float (A-C)	1,109,731,962	1,109,731,962 *(but see Item 14.2)*	100%	100% *(but see Item 14.2)*

Public Securityholders (Registered)

Instruction: *For the purposes of this report, "public securityholders" are persons other than persons enumerated in section (B) of the previous chart. List registered holders only.*

Class of Security: **COMMON TRUST UNITS**

Size of Holding	Number of holders	Total number of securities
1 – 99 securities		
100 – 499 securities		
500 – 999 securities		
1,000 – 1,999 securities		
2,000 – 2,999 securities		
3,000 – 3,999 securities		
4,000 – 4,999 securities		
5,000 or more securities	1,296	1,108,989,038
	1,296	1,108,989,038

Public Securityholders (Beneficial)

Instruction: *Include (i) beneficial holders holding securities in their own name as registered shareholders; and (ii) beneficial holders holding securities through an intermediary where the Issuer has been given written confirmation of shareholdings. For the purposes of this section, it is sufficient if the intermediary provides a breakdown by number of beneficial holders for each line item below; names and holdings of specific beneficial holders do not have to be disclosed. If an intermediary or intermediaries will not provide details of beneficial holders, give the aggregate position of all such intermediaries in the last line.*

Class of Security: COMMON TRUST UNITS

Size of Holding	Number of holders	Total number of securities
1 – 99 securities		
100 – 499 securities		
500 – 999 securities		
1,000 – 1,999 securities		
2,000 – 2,999 securities		
3,000 – 3,999 securities		
4,000 – 4,999 securities		
5,000 or more securities	1,296 *(see note below)*	1,108,989,038
	1,296	1,108,989,038

Note: All common trust units registered to known intermediaries are registered in a manner that identifies a named beneficiary or account number (e.g., "Intermediary ITF Named Beneficiary" or "Intermediary ITF Specified Account Number"). To the Issuer's knowledge, each such registration relates to a single beneficial holder and, accordingly, each registered holder corresponds to a single beneficial holder.

Non-Public Securityholders (Registered)

Instruction: *For the purposes of this report, "non-public securityholders" are persons enumerated in section (B) of the issued capital chart.*

Class of Security: COMMON TRUST UNITS

Size of Holding	Number of holders	Total number of securities
1 – 99 securities		
100 – 499 securities		
500 – 999 securities		
1,000 – 1,999 securities		
2,000 – 2,999 securities		
3,000 – 3,999 securities		
4,000 – 4,999 securities		
5,000 or more securities	1	742,924
	1	742,924

14.2 Provide the following details for any securities convertible or exchangeable into any class of listed securities:

Description of Security (include conversion / exercise terms, including conversion / exercise price)	Number of convertible / exchangeable securities outstanding	Number of listed securities issuable upon conversion / exercise
6% convertible debenture due June 2022	$217,000 aggregate principal amount	DEPENDS ON TRADING PRICE (principal amount convertible into Trust Units at a conversion price equal to 20-day volume-weighted average trading price)

The only security convertible or exchangeable into Trust Units and currently outstanding is a $217,000 convertible debenture issued to the vendor of certain assets acquired during 2015.

The debenture is secured by the assets acquired, bears interest at the rate of 6% per annum, and has a 7-year term maturing June 30, 2022.

If the Trust Units are listed on the Canadian Securities Exchange or another qualified stock exchange or market, the principal amount of the debenture is convertible, at the holder's election, into Trust Units at a conversion price per unit equal to a 20-day volume-weighted average trading price of the Trust Units.

As the conversion price of the debenture will vary according to the trading price of the underlying Trust Units from time-to-time, the number of Trust Units potentially issuable on conversion cannot be determined with certainty.

14.3 Provide details of any listed securities reserved for issuance that are not included in section 14.2.

NONE

Part IV – Certificate of the Issuer

Pursuant to resolutions duly passed by the trustees of Petrocapita Income Trust (the "Trust") and by the directors of its administrator, Petrocapita GP I Ltd. (the "Administrator"), the Administrator, for and on behalf of the Trust, hereby applies for the listing of the above mentioned securities on the Canadian Securities Exchange. The foregoing contains full, true and plain disclosure of all material information relating to the Trust. It contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to prevent a statement that is made from being false or misleading in light of the circumstances in which it was made.

DATED at Calgary, Alberta this 5th day of November, 2015.

PETROCAPITA INCOME TRUST, by its Administrator, Petrocapita GP I Ltd.

By: *(signed) "Alex Lemmens"*
Alex Lemmens
Chairman, President
and Chief Executive Officer

By: *(signed) "Evelyn Studer"*
Evelyn Studer
Vice President, Finance
and Chief Financial Officer

By: *(signed) "Greg Marr"*
Greg Marr
Director

By: *(signed) "Ben Van Rootselaar"*
Ben Van Rootselaar
Director