2016

ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2016

QUESTERRE ENERGY CORPORATION IS LEVERAGING ITS EXPERTISE GAINED THROUGH EARLY EXPOSURE TO SHALE AND OTHER NON-CONVENTIONAL RESERVOIRS.

THE COMPANY HAS BASE PRODUCTION AND RESERVES IN THE TIGHT OIL BAKKEN/TORQUAY OF SOUTHEAST SASKATCHEWAN.

IT IS BRINGING ON PRODUCTION FROM ITS LANDS IN THE HEART OF THE HIGH-LIQUIDS MONTNEY SHALE FAIRWAY.

IT IS A LEADER ON SOCIAL LICENSE TO OPERATE ISSUES FOR ITS GIANT UTICA SHALE GAS DISCOVERY IN QUEBEC.

IT IS PURSUING OIL SHALE PROJECTS WITH THE AIM OF COMMERCIALLY DEVELOPING THESE SIGNIFICANT RESOURCES.

QUESTERRE IS A BELIEVER THAT THE FUTURE SUCCESS OF THE OIL AND GAS INDUSTRY DEPENDS ON A BALANCE OF ECONOMICS, ENVIRONMENT AND SOCIETY. WE ARE COMMITTED TO BEING TRANSPARENT AND ARE RESPECTFUL THAT THE PUBLIC MUST BE PART OF MAKING THE IMPORTANT CHOICES FOR OUR ENERGY FUTURE.

QUESTERRE'S COMMON SHARES TRADE ON THE TORONTO STOCK EXCHANGE AND OSLO STOCK EXCHANGE UNDER THE SYMBOL QEC.

President's message

In spite of a difficult two years, we made important progress during the downturn. This came from four places: efficiency improvements in the Montney, steadfast step by step work in Quebec, the resource delineation in Jordan and preserving our liquidity.

Highlights

- Quebec government endorses new hydrocarbon legislation
- Quebec Resource Assessment includes best estimate of risked economic contingent resources of 314 Bcf (52 million boe) with a risked NPV-10 of $424 million
- Jordan Resource Assessment best estimate of discovered petroleum initially in place of between 7.8 billion barrels to 12.2 billion barrels
- Corporate total proved plus probable reserves of 15.78 MMboe with a before income tax NPV-10% of $155.59 million
- Adjusted funds flow from operations of $7.05 million with average daily production of 1,373 boe/d for the year

Kakwa-Resthaven, Alberta

We continued to move up the learning curve with better well performance at Kakwa. Longer horizontal wells with more effective completions, including increased sand tonnage, have seen a 20% uptick in initial production over the first thirty days from new wells compared to last year.

With these improved results, we plan to participate in up to eight gross wells this year. Our drilling program is on schedule with two of these wells already drilled and awaiting completion in the second quarter.

We expect the returns on these and future wells will benefit from the expanded field infrastructure. A central water facility to store produced water for fracs will lower completion costs going forward. A sweetening unit will also be commissioned this spring to reduce chemical costs by about $3/boe. The joint venture is also contemplating a further expansion of the central facilities to 60 MMcf/d and associated liquids early next year.

St. Lawrence Lowlands, Quebec

The introduction of a new oil and gas law in Quebec was largely because Questerre proactively engaged the government and other stakeholders. This was a huge step forward after six years of public consultations and studies. The next milestone is the passage of the associated hydrocarbon and environmental regulations.

We commissioned GLJ Petroleum Consultants to update our Utica resource assessment. Their report confirms the scale of our resource and the economics of development. Results from the Ohio Utica have shown the benefits of new technology on efficiency and economics. It also shows how this technology has lower environmental impacts.

Environmental impacts are important to local acceptability, another prerequisite for development. To this end, our contingent resources are focused in areas with low population density and specifically excluding urban areas.

Oil Shale Mining

Just like our Utica acreage in Quebec, we have captured a very high quality resource in Jordan. Our main goals were to get independent confirmation of the scale and quality of this resource and figure out how to develop this resource profitably.

An independent assessment by Millcreek Mining Group supports our view of the scale of this deposit. Using a 2:1 ratio of overburden to ore that would be reasonable to mine, the assessment estimates discovered petroleum initially-in-place of 7.8 billion barrels. The report also confirmed the richness of the oil yield and little to no inter-burden.

We are testing this shale and its suitability for multiple retorting processes including two that are commercially proven and the Eco-Shale process, developed by Red Leaf. We have commissioned several scoping studies and the preliminary results support further work on this project. Ultimately, we plan to seek a strategic relationship with the leading technology.

Operational & Financial

To preserve liquidity, we reduced capital spending by 30% over last year and continued to reduce overheads by about 25%. This contributed to a nominal decrease in production to 1,373 boe/d from 1,582 boe/d last year. Oil and condensate still represent over 50% of volumes. With lower commodity prices, adjusted funds from operations was $7.02 million compared to $9.78 million in 2015.

While the restricted capital and overhead reductions have allowed us to stay within our credit facilities, we improved our liquidity in the year with two private placements for gross proceeds of $12 million. In 2017, we raised an additional $24 million to further strengthen our balance sheet.

Outlook

We are very optimistic about our future.

Although natural gas prices have dropped substantially since 2010, the significant upside of our Utica acreage remains, driven by the excellent results of the US Utica and premium pricing in Quebec. We are focused on the next steps of regulations and social acceptability.

We are continuing to appraise our oil shale acreage in Jordan. The goal is to make this multi-billion barrel deposit economic in a modestly higher oil price environment.

Underpinning the potential of Quebec and Jordan is our producing Montney acreage at Kakwa. Our 2017 drilling program should see further improvements in well performance. We are hopeful this will translate to more robust economics that sees us growing production and cash flow this year despite the volatility in commodity prices.

Michael Binnion, President and Chief Executive Officer

Kakwa-Resthaven, Alberta

The Kakwa-Resthaven area is situated approximately 75 kilometres south of Grande Prairie in west central Alberta. Among other zones of interest, the area is prospective for condensate-rich natural gas in the deep, over-pressured fairway of the Montney formation, at a depth of approximately 3,100 metres to 3,600 metres. Questerre's wells are currently targeting one of three prospective intervals in the Upper Montney formation. Economics are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives.

Questerre currently holds 20,320 (11,880 net) acres in the area, including a 100% working interest and operatorship of 8,320 net acres. In addition, the Company holds a further 8,320 net acres in the Wapiti area, approximately 20 miles to the northwest also prospective for the Montney formation.

Initial development of the Montney focused on areas of dry gas or relatively low liquids of approximately 25 bbls/MMcf in British Columbia. With changes in the natural gas market, activity shifted to target sweet spots where natural gas liquids rates are higher. With test rates from its wells as high as 200 bbls/MMcf, the Company's acreage is in one of the sweet spots of this liquids-rich fairway. More importantly, liquids from these wells are mainly condensate which retains a premium to light oil and liquids prices because it is used as a diluent for bitumen and heavy oil production in Alberta.

Consistent with 2015, the majority of activity in the year was conducted on its joint venture acreage where it holds an approximate 25% working interest. In 2016, to preserve financial liquidity, the Company selectively participated in the drilling program and held an interest in two (0.50 net) of the six (1.50 net) wells drilled during the year. The Company can elect to earn an interest in the remaining four wells once the operator has received net revenue equivalent to four times the drilling and completion costs and two times the equipping and tie-in costs of each well. The Company also participated in an expansion of existing infrastructure on this acreage.

Production from this area averaged 1,037 boe/d in 2016 with liquids, primarily condensate, accounting for 50% of this amount.

In 2016, the average length of the horizontal section increased to 2,297 metres or 10% longer than the prior year. Leveraging the improvements in completion design from prior years, completions benefitted from increased sand tonnage and tighter inter-treatment spacing. Over the first thirty days, average production from the six wells drilled in 2016 was 4.2 MMcfe/d. By comparison in 2015, the average production over the first thirty days from the wells completed and placed on production during the year were 3.5 MMcfe/d. While the initial results are encouraging the results are not necessarily indicative of long term performance or ultimate recovery from these wells.

Questerre also participated in the expansion of field infrastructure on its joint venture acreage for future development. This included the acquisition of a regenerative amine sweetening system and construction of a water storage facility. The amine sweetening system, with a design capacity of 60 MMcf/d and up to 1 tonne of sulphur per day, will replace the non-regenerative chemical sweetening process and should lower operating costs. The water storage facility will temporarily store produced water and will be used for future completion operations. During the year, limited activity was conducted on the Company's operated acreage in the area given the commodity price environment. Based on the recent positive results directly offsetting its operated acreage to the north, the Company is contemplating development options in the second half of this year.

For 2017, subject to commodity prices and continued results, the Company plans to participate in the gross capital budget of $100 million ($25 million net) proposed by the operator. This will include the drilling of up to 8 (2.0 net) wells and additional infrastructure including gas lift facilities and pipelines.

Antler, Saskatchewan

The Antler area is approximately 200 kilometres from Regina in southeast Saskatchewan. The primary target is high quality light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1,050 metres and 1,150 metres. Secondary targets include the Souris Valley, a carbonate sequence at a depth of approximately 900 metres to 1,000 metres. The Company holds an average 64% working interest in 11,351 acres in this area.

Production from this area averaged 209 bbl/d in 2016.

In 2016, activities at Antler targeted the optimization of existing production and the pilot waterflood to increase recovery of the oil in place.

The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,100 bbls/d of water into the oil pool. The preliminary results from the waterflood remain supportive of further work to assess an expansion to adjacent sections.

In 2017, the Company also plans to continue work to optimize production subject to partner participation and results.

St. Lawrence Lowlands, Quebec

The Lowlands are situated in Quebec, south of the St. Lawrence River between Montreal and Quebec City. The exploration potential of the Lowlands is complemented by proximity to one of the largest natural gas markets in North America and a well-established distribution network.

The area is prospective for natural gas in several horizons with the primary target being the Utica shale. Secondary targets include the shallower Lorraine silts and shale and the deeper Trenton Black-River carbonate. The majority of Questerre's one million gross acres lies in the heart of the fairway between two major geological features — Logan's Line, a subsurface thrust fault to the east and the Yamaska growth fault to the west.

Following a successful vertical test well program in 2008 and 2009, Questerre and its partner, Repsol Oil & Gas Canada Inc. (formerly Talisman Energy Inc.), began a pilot horizontal well program to assess commerciality of the Utica shale in 2010. In the fall of 2010, the pilot program was suspended while the provincial government initiated an environmental assessment of shale gas development in the province.

Following almost six years of extensive studies and public consultation, in December 2016, the Government of Quebec passed Bill 106, *An Act to implement the 2030 Energy Policy and amend various legislative provisions*. These amendments include the enactment of the *Petroleum Resources Act* to govern the future development of petroleum resources in Quebec.

Pursuant to its schedule, the government plans to introduce the associated hydrocarbon regulations in early 2017. In March 2017, the government enacted Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund,* which brings a number of amendments to the *Environmental Quality Act* mainly to modernize the environmental schemes it prescribes, in particular to take climate change issues more fully into account. These amendments will come into force gradually over the next two years.

Along with social acceptability, these hydrocarbon and environmental regulations are prerequisites to the resumption of field activities to assess the Company's Utica gas discovery in the province.

In early 2017, the Company updated the resource assessment of its Utica acreage in Quebec (the "Quebec Resource Assessment"). The best estimate by the Company's independent reserve engineers of unrisked Prospective Resources net to Questerre is 5.8 trillion cubic feet ("Tcf") (965 million barrels of oil equivalent ("boe")). Additionally, the Quebec Resource Assessment details the best estimate of unrisked Contingent Resources net to Questerre is 898 Bcf (150 million boe) and risked Contingent Resources, net to Questerre, is 314 Bcf (52 million boe). The net present value of the risked Economic Contingent Resources, including the development on hold and development unclarified sub categories, discounted at 10% before tax is estimated at $424 million.

The updated Quebec Resource Assessment assigned Economic Contingent Resources for approximately 16% of Questerre's acreage based on the test results from the Company's Utica wells. The test results from these wells were reported by Questerre in 2008 to 2010. The chance of commercial development for these Economic Contingent Resources was based on population density, ability to secure local acceptability to operate, the ability to apply new technology to environmental issues and other factors. As a result, the Company's acreage has been high-graded by individual regional county municipality ("RCM") with chance of commercial development currently ranging from 10% to 70%.

The Quebec Resource Assessment was conducted by GLJ Petroleum Consultants ("GLJ"), an independent qualified reserves evaluator, with an effective date of 31 December 2016. It assesses the Utica Shale gas potential within the Company's 735,910 gross acres in the St. Lawrence Lowlands of Quebec. The Quebec Resource Assessment was prepared in accordance with National Instrument 51-101 and the COGE Handbook.

The Quebec Resource Assessment is based on the results from several vertical and horizontal wells on the Company's acreage that have all encountered pay in the Utica. Test data from these wells, in conjunction with offset development and studies of the analogous US Utica, supports the prospective commercial development of these resources.

Contingent Resource volumes have been classified as development on hold or development unclarified. In those areas classified as development on hold, including the less densely populated areas of Lotbiniere and Becancour, development is primarily contingent on the passage of applicable hydrocarbon and environmental legislation and regulations as well as local acceptability. Remaining areas classified as development unclarified have additional contingency or risk associated with securing social license to operate and are thereby a lower priority for development. Additional contingencies include firm development plans, detailed cost estimates and corporate approvals and sanctioning. There is no certainty that any portion of the Contingent Resources will be economic to develop.

The Contingent Resources have been risked for the chance of commerciality, or commercial development, defined as the product of the chance of discovery and the chance of development. For Contingent Resources, the chance of discovery is equal to one. The chance of development is the estimated probability that once discovered, a known accumulation will be commercially developed.

For more information, please refer to the Company's 2016 Annual Information Form ("AIF") and press release dated February 8, 2017 available on the Company's website at www.questerre.com and on SEDAR at www.sedar.com.

Oil Shale Mining

Questerre's principal oil shale asset is its acreage in the Kingdom of Jordan ("Jordan").

The Company acquired the project in 2015 through a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale with the Ministry of Energy and Mineral Resources in Jordan. The MOU covers an area of over 380 square kms in the Isfir-Jafr area, approximately 200 km south of the capital Amman. The term of the MOU was recently extended to May 22, 2018.

The Company's primary objectives for 2016 were to evaluate the scale and nature of the resource and the feasibility of commercial development.

In October 2016, Questerre commissioned an independent assessment of its oil shale resources in Jordan (the "Jordan Resource Assessment"). The Jordan Resource Assessment was conducted by Millcreek Mining Group, an independent qualified reserves evaluator, as defined by NI 51-101 with an effective date of September 30, 2016. The assessment was prepared in accordance with NI 51-101 and the COGE Handbook. The assessment indicated a best estimate of discovered petroleum initially in place of between 7.8 billion barrels to 12.2 billion barrels. For more information, please refer to the Company's press release dated October 27, 2016 available on the Company's website at www.questerre.com or on SEDAR at www.sedar.com.

The economic feasibility work involves assessing multiple retorting processes, including two processes that have been proven at commercial scale. Also under evaluation is the Eco-Shale process, a proprietary process to recover oil from shale developed by Red Leaf Resources Inc. ("Red Leaf"), a private Utah-based oil shale and technology company.

In conjunction with the assessment of retorting processes, the Company has commissioned and finalized three engineering studies for the mining, preparation of ore and upgrading of the produced oil and other products. Two additional studies for marketing the finished products and infrastructure, including utilities, are scheduled for completion in 2017. The Company anticipates incorporating the results from these studies in a subsequent update of its independent resource assessment.

Questerre's other oil shale assets includes acreage prospective for oil shale in Pasquia Hills, Saskatchewan, and the licensing rights to Red Leaf's EcoShale process. Red Leaf's principal assets are the EcoShale process and oil shale leases in the state of Utah. Questerre currently holds approximately 6% of the equity capital of Red Leaf.

In 2016, Red Leaf was advised by its partner, a US affiliate of the French-based supermajor, Total S.A., ("Total") that it intends to withdraw from the joint venture to commercialize the EcoShale process. The parties are currently negotiating the terms of Total's withdrawal from the project.

As a result of this delay with the EcoShale process and low commodity prices, the Company plans to relinquish the rights to its oil shale acreage at Pasquia Hills in early 2017.

Environmental Stewardship

Questerre is committed to the economic development of resources in an environmentally conscious and socially responsible manner. We acknowledge that, like all industries, we impact the environment. Although this impact cannot be completely eliminated, we can ensure that our footprint is minimized. Questerre believes in a prudent approach to the sourcing, use and disposal of water for drilling and completion operations in compliance with strict environmental regulations. Wherever possible, we recycle and reuse water. Where produced water cannot be recycled, we dispose of it responsibly at controlled sites in accordance with government regulations.

Our surface rights are shared with stakeholders including the landowners and the government. Horizontal drilling and multi-well pads keep disturbance to a minimum by reducing the number of drilling pads required. Commercial development will use central facilities for drilling, completion and production operations to further reduce surface disturbance. We constantly invest in new technologies and adopt best practices that help us keep our surface footprint to a minimum. Our focus in Quebec is on natural gas, the cleanest fossil fuel. Production close to markets saves on transportation and reduces overall emissions. We support the use of technology to improve efficiencies and reduce emissions from our operations.

Management's Discussion and Analysis ("MD&A") was prepared as of March 24, 2017. This MD&A should be read in conjunction with the audited consolidated financial statements of Questerre Energy Corporation ("Questerre" or the "Company") as at and for the years ended December 31, 2016 and 2015. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2016 ("AIF"), is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is actively involved in the acquisition, exploration and development of oil and gas projects, and, in specific, non-conventional projects such as tight oil, oil shale, shale oil and shale gas. Questerre is committed to the economic development of its resources in an environmentally conscious and socially responsible manner.

The Company's Class "A" common voting shares ("Common Shares") are listed on the Toronto Stock Exchange and the Oslo Stock Exchange under the symbol "QEC".

Basis of Presentation

Questerre presents figures in the MD&A using accounting policies within the framework of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, representing generally accepted accounting principles ("GAAP"). All financial information is reported in Canadian dollars, unless otherwise noted.

Forward-Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "assume", "believe", "budget", "can", "commitment", "continue", "could", "estimate", "expect", "forecast", "foreseeable", "future", "intend", "may", "might", "plan", "potential", "project", "will" and similar expressions. 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. Management believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A.

This MD&A contains forward-looking statements including, but not limited to, those pertaining to the following:

- drilling plans and the development and optimization of producing assets;
- future production of oil, natural gas and natural gas liquids;
- future commodity prices;
- legislative and regulatory developments in the Province of Quebec;
- liquidity and capital resources;
- the Company's compliance with the terms of its credit facility;
- timing of the next review of the Company's credit facility by its lender;
- ability of the Company to meet its foreseeable obligations;

- expectations regarding the Company’s liquidity increasing over time;
- capital expenditures and the funding thereof;
- impacts of capital expenditures on the Company’s reserves and resources;
- updating the independent Resource Assessment of the Company’s oil shale resources in Jordan;
- the relinquishment of the Company’s oil shale acreage at Pasquia Hills;
- usage and expansion of joint venture infrastructure in the Kakwa-Resthaven area;
- average royalty rates;
- commitments and Questerre’s participation in future capital programs;
- risks and risk management;
- potential for equity and debt issuances and farm-out arrangements;
- counterparty creditworthiness;
- joint venture partner willingness to participate in capital programs;
- flow-through shares and use of proceeds and renunciation and indemnity obligations associated therewith;
- insurance;
- use of financial instruments;
- critical accounting estimates and;
- timing and type of economic feasibility studies.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A, the Company’s AIF, dated March 24, 2017, and the documents incorporated by reference into this document:

- volatility in market prices for oil, natural gas liquids and natural gas;
- counterparty credit risk;
- access to capital;
- the terms and availability of credit facilities;
- changes or fluctuations in oil, natural gas liquids and natural gas production levels;
- liabilities inherent in oil and natural gas operations;
- adverse regulatory rulings, orders and decisions;
- attracting, retaining and motivating skilled personnel;
- uncertainties associated with estimating oil and natural gas reserves and resources;
- competition for, cost and availability of, among other things, capital, acquisitions of reserves, undeveloped lands, equipment, skilled personnel and services;
- incorrect assessments of the value of acquisitions and targeted exploration and development assets;
- fluctuations in foreign exchange or interest rates;
- stock market volatility, market valuations and the market value of the securities of Questerre;
- failure to realize the anticipated benefits of acquisitions;
- actions by governmental or regulatory authorities, including changes in royalty structures and programs, and income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- limitations on insurance;

- changes in environmental, tax, or other legislation applicable to the Company’s operations, and its ability to comply with current and future environmental and other laws; and
- geological, technical, drilling and processing problems, and other difficulties in producing oil, natural gas liquids and natural gas reserves.

Statements relating to “reserves” or “resources” are by their nature deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

The discounted and undiscounted net present values of future net revenue attributable to reserves and resources do not represent the fair market value thereof.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law. Certain information set out herein with respect to forecasted results is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company’s reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

BOE Conversions

Barrel of oil equivalent (“boe”) amounts may be misleading, particularly if used in isolation. A boe conversion ratio has been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil and is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Non-GAAP Measures

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed under GAAP. As these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

This document contains the term “adjusted funds flow from operations”, which is an additional non-GAAP measure. The Company uses this measure to help evaluate its performance.

As an indicator of the Company’s performance, adjusted funds flow from operations should not be considered as an alternative to, or more meaningful than, net cash from operating activities as determined in accordance with GAAP. The Company’s determination of adjusted funds flow from operations may not be comparable to that reported by other companies. Questerre considers adjusted funds flow from operations to be a key measure as it demonstrates the Company’s ability to generate the cash necessary to fund operations and support activities related to its major assets.

Adjusted Funds Flow from Operations Reconciliation

($ thousands)		2016		2015
Net cash from operating activities	$	6,719	$	8,957
Interest paid		912		225
Change in non-cash working capital		(586)		596
Adjusted funds flow from operations	$	7,045	$	9,778

This document also contains the terms "operating netbacks", "cash netbacks" and "working capital surplus (deficit)", which are non-GAAP measures.

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating and cash netbacks, as presented, do not have any standardized meaning prescribed by GAAP and may not be comparable with the calculation of similar measures for other entities. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

The Company also uses the term "working capital surplus (deficit)". Working capital surplus (deficit), as presented, does not have any standardized meaning prescribed by GAAP, and may not be comparable with the calculation of similar measures for other entities. Working capital surplus (deficit), as used by the Company, is calculated as current assets less current liabilities excluding the current portion of the share based compensation liability and risk management contracts.

Select Annual Information

As at/for the years ended December 31,	2016	2015	2014 [1]
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**17,120**	22,015	28,577
Adjusted Funds Flow from Operations	**7,045**	9,778	14,890
Basic and Diluted ($/share)	**0.03**	0.04	0.06
Net Income (loss)	**169**	(73,534)	(36,738)
Basic and Diluted ($/share)	**-**	(0.28)	(0.14)
Capital Expenditures, net of			
Acquisitions and Dispositions	**14,218**	20,524	56,646
Working Capital Surplus (Deficit)	**(17,019)**	(21,478)	(9,247)
Total Non-Current Financial Liabilities	**8,726**	9,370	8,235
Total Assets	**177,761**	161,894	232,770
Shareholders' Equity	**139,660**	127,453	200,641
Common Shares Outstanding (thousands)	**308,274**	264,932	264,932
Weighted average - basic (thousands)	**278,662**	264,932	264,890
Weighted average - diluted (thousands)	**280,410**	264,932	265,703
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**801**	913	749
Natural Gas (Mcf/d)	**3,436**	4,012	1,959
Total (boe/d)	**1,373**	1,582	1,076
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**47.51**	51.75	90.84
Natural Gas ($/Mcf)	**2.55**	3.26	5.25
Total ($/boe)	**34.06**	38.13	72.76
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**34.06**	38.13	72.76
Royalties Expense	**(1.86)**	(2.16)	(5.80)
Percentage	**5%**	6%	8%
Operating Expense	**(15.23)**	(13.97)	(14.36)
Operating Netback	**16.98**	22.00	52.60
General and Administrative Expense	**(5.49)**	(6.14)	(12.11)
Cash Netback	**11.48**	15.86	40.49
Wells Drilled			
Gross	**3.00**	1.00	16.00
Net	**0.75**	0.25	5.80

[1] Certain 2014 figures have been revised. Refer to note 2 of the December 31, 2015 annual financial statements.

Highlights

- Quebec government endorses new hydrocarbon legislation
- Quebec Resource Assessment effective as of December 31, 2016 includes best estimate of risked economic contingent resources of 314 Bcf (52 million boe) with a risked NPV-10 of $424 million[(1)]
- Jordan Resource Assessment effective as of September 30, 2016 best estimate of discovered petroleum initially in place of between 7.8 billion barrels to 12.2 billion barrels[(2)]
- Corporate total proved plus probable reserves of 15.78 MMboe with a before income tax NPV-10% of $155.59 million
- Adjusted funds flow from operations of $7.05 million for 2016 with average daily production of 1,373 boe/d

(1) There is no certainty that it will be commercially viable to produce any portion of the resources.

(2) There is no certainty that any portion of the resources will be discovered. If discovered there is no certainty that it will be commercially viable to produce any portion of the resources.

2016 Activities

Western Canada

Kakwa-Resthaven, Alberta

Representing over 75% of production and capital investment over the last two years, development of the condensate-rich Montney in this core area remained a focus for the Company. Questerre currently holds 20,320 (11,880 net) acres in the area, including a 100% working interest and operatorship of 8,320 net acres. In addition, the Company holds a further 8,320 net acres in the Wapiti area, approximately 20 miles to the northwest which is also prospective for the Montney formation.

A total of six gross wells were drilled, completed and placed on production on the Company's joint venture acreage during the year. These include the 03-18-63-5W6M well (the "03-18 Well"), the 06-18-63-5W6M well, the 16-20-63-5W6M well (the "16-20 Well"), 102/16-20-63-5W6M well, the 04-16-63-6W6M well and the 05-16-63-6W6M well. To preserve financial liquidity, Questerre selectively participated in this program and holds a 25% working interest in two wells, the 03-18 Well and the 16-20 Well. The Company can elect to earn an interest in the remaining four wells once the operator has received net revenue equivalent to four times the drilling and completion costs and two times the equipping and tie-in costs of each well. Additionally, in December 2016, the operator spud the 10-15-63-6W6M well (the "10-15 Well") on the joint venture acreage. Questerre holds a 25% working interest in the 10-15 Well. Drilling operations were completed and the 10-15 well is scheduled for completion and tie-in in the second quarter of 2017.

In 2016, the length of the horizontal section for these wells increased to 2,297 metres or approximately 10% longer than the prior year. Leveraging the improvements in completion design from prior years, completions in 2016 benefitted from increased sand tonnage and tighter inter-treatment spacing. Over the first thirty days, average production from the six wells drilled in 2016 was 4.2 MMcfe/d, 20% higher than the 30 day average for wells completed and placed on production during 2015. While the initial results are encouraging the results are not necessarily indicative of long term performance or ultimate recovery from these wells.

Questerre also participated in the expansion of field infrastructure on its joint venture acreage, investing approximately $3.32 million in 2016. This included the acquisition of a regenerative amine sweetening system and construction of a water storage facility. The amine sweetening system, with a design capacity of 60 MMcf/d and up to 1 tonne of sulphur per day, will replace the non-regenerative chemical sweetening process and should lower operating costs. The water storage facility will temporarily store produced water and will be used for future completion operations.

In 2016, limited activity was conducted on the Company's operated acreage in the area given the lower commodity price environment. Based on the results directly offsetting its operated acreage to the north, the Company is contemplating development options in the second half of 2017.

For 2017, subject to commodity prices and continued results, the Company plans to participate in the gross capital budget of $100 million ($25 million net) proposed by the operator. This will include the drilling of up to 8 (2.0 net) wells and additional infrastructure, including gas lift facilities and pipelines. As of the date of this report, two (0.5 net) wells have been drilled and completed and drilling of the third is underway.

Antler, Saskatchewan

Consistent with prior years, activities at Antler targeted the optimization of existing production and the pilot waterflood to increase recovery of the oil in place.

The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,100 bbls/d of water into the oil pool. The preliminary results from the waterflood remain supportive of further work to assess an expansion to adjacent sections.

In 2017, the Company also plans to continue work to optimize production subject to partner participation and results.

St. Lawrence Lowlands, Quebec

In the fourth quarter of 2016, the National Assembly in Quebec passed as law Bill 106, *An Act to implement the 2030 Energy Policy and amend various legislative provisions*. These amendments include the enactment of the *Petroleum Resources Act* to govern the future development of petroleum resources in Quebec. This follows almost six years of public consultations and extensive studies.

Pursuant to its schedule, the Quebec government plans to introduce the associated hydrocarbon regulations in early 2017. In March 2017, the government enacted Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*.

Along with social acceptability, these hydrocarbon and environmental regulations are prerequisites to the resumption of field activities to assess the Company's Utica gas discovery in the province.

In early 2017, the Company updated the resource assessment of its Utica acreage in Quebec (the "Quebec Resource Assessment"). The Quebec Resource Assessment was conducted by GLJ Petroleum Consultants ("GLJ"), an independent qualified reserves evaluator, with an effective date of December 31, 2016. It assesses the Utica Shale gas potential within the Company's 735,910 gross (190,800 net) acres in the St. Lawrence Lowlands of Quebec. The Quebec Resource Assessment was prepared in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities of the Canadian Securities

Administrators ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook Volume I ("COGE Handbook").

The best estimate by the Company's independent reserve engineers of unrisked Prospective Resources net to Questerre is 5.8 trillion cubic feet ("Tcf") (965 million barrels of oil equivalent ("boe")). Additionally, the Quebec Resource Assessment details the best estimate of unrisked Contingent Resources, net to Questerre, is 898 Bcf (150 million boe) and risked Contingent Resources net to Questerre is 314 Bcf (52 million boe). The net present value of the risked Economic Contingent Resources, including the development on hold and development unclarified sub categories, discounted at 10% before tax is estimated at $424 million.

An estimate of risked net present value of future revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the investment. It involves Contingent Resources that are considered too uncertain with respect to development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized. Further estimated values of future net revenue do not represent fair market value.

The updated Quebec Resource Assessment assigned Economic Contingent Resources for approximately 16% of Questerre's acreage based on the test results from the Company's Utica wells. The test results from these wells were reported by Questerre in 2008 to 2010. The chance of commercial development for these Economic Contingent Resources was based on population density, ability to secure local acceptability to operate, the ability to apply new technology to environmental issues and other factors. As a result, the Company's acreage has been high-graded by individual regional county municipality ("RCM") with chance of commercial development ranging from 10% to 70%.

The Quebec Resource Assessment is based on the results from several vertical and horizontal wells on the Company's acreage that have all encountered pay in the Utica. Test data from these wells, in conjunction with offset development and studies of the analogous US Utica, supports the prospective commercial development of these resources.

Contingent Resource volumes have been classified as development on hold or development unclarified. Development in those areas classified as development on hold, including the less densely populated areas of Lotbiniere and Becancour, are primarily contingent on the passage of applicable hydrocarbon and environmental legislation and regulations as well as local acceptability. Remaining areas classified as development unclarified have additional contingency or risk associated with securing social license to operate and are thereby a lower priority for development. Additional contingencies include firm development plans, detailed cost estimates and corporate approvals and sanctioning. There is uncertainty that it will be commercially viable to produce any portion of the Contingent Resources.

The Contingent Resources have been risked for the chance of commerciality, or commercial development, defined as the product of the chance of discovery and the chance of development. For Contingent Resources, the chance of discovery is equal to one. The chance of development is the estimated probability that once discovered, a known accumulation will be commercially developed. Prospective Resources were also risked for chance of discovery. There is no certainty that any portion of Prospective Resources will be discovered. If discovered there is no certainty that it will be economically viable to produce any portion of the Prospective Resource.

Development of the Contingent Resources is based on low, best and high estimate type curves with Expected Ultimate Recoveries ("EUR") of 5.5 Bcf, 9 Bcf and 15 Bcf respectively. The type curve assumes wells with horizontal sections of approximately 2400 metres and 24 fracture stages. These estimates are based on performance of analogous wells in the US Utica and Marcellus shale, test data of the Quebec Utica forecast to ultimate recoveries and publically available type curve information published by other industry operators. Pad development of approximately 8 wells per pad is expected to be based on 400m spacing between wells, or 2.7 wells per square mile. The first commercial production associated with the development of Contingent Resources is scheduled for 2019 based on development timing as estimated by the Company.

Significant positive factors relevant to the estimate of the Company's resources include the importation of all natural gas consumed in Quebec creating demand for local production, premium realized pricing due to the transportation costs associated with importing natural gas for consumption, production test data from the Company's existing wells and the development of the analogous Utica shale in the United States. Significant negative factors include the limited number of wells on the Company's acreage, lack of a developed service sector providing uncertainty regarding estimates of capital and operating costs, developing hydrocarbon regulations and environmental legislation and the requirement to obtain social acceptability for oil and gas operations.

While the Company believes it will have sufficient financial capability to fund its share of costs associated with the development program in the Quebec Resource Assessment, it may not have access to the necessary capital when required. Conducting the development program is also dependent on the participation by the Company's joint venture partners. There is no guarantee that they will elect to participate in the program to the extent required. The Company retains the right to conduct activities without the operators' participation on an independent operations basis whereby it can fund 100% of the capital costs for certain well operations and facilities in return for net revenue equal to 400% of its capital investment before the operators can elect to either remain in a penalty position or hold a working interest.

For more information, please refer to the Company's 2016 AIF and the press release dated February 8, 2017 available on the Company's website at www.questerre.com and on SEDAR at www.sedar.com.

Oil Shale Mining

Questerre continued the appraisal of its oil shale project in the Kingdom of Jordan ("Jordan") during the year.

The Company acquired the project in 2015 through a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale with the Ministry of Energy and Mineral Resources in Jordan. The MOU covers an area of over 380 square kms in the Isfir-Jafr area, approximately 200 km south of the capital Amman. The Company holds a 100% working interest in the MOU and the resources. The term of the MOU was recently extended to May 22, 2018.

The Company's primary objectives for 2016 were to evaluate the scale and nature of the resource and the feasibility of commercial development.

In October 2016, Questerre commissioned an independent assessment of its oil shale resources in Jordan (the "Jordan Resource Assessment"). The Jordan Resource Assessment was conducted by Millcreek Mining Group, an independent qualified reserves evaluator, as defined by NI 51-101 with an effective date of September 30, 2016. The assessment was prepared in accordance with NI 51-101 and the COGE Handbook. The assessment indicated a best estimate of discovered petroleum initially in place of between 7.8 billion barrels to 12.2 billion barrels. Although the Company is in the process of completing a conceptual study, at this time, given the preliminary nature of the Jordan Resources Assessment, it does not contain any estimates regarding the timing or cost to obtain commercial development nor has the Company finalized the specific technology to be used. For more information, please refer to the Company's press release dated October 27, 2016 and the 2016 AIF available on the Company's website at www.questerre.com or on SEDAR at www.sedar.com.

The economic feasibility work involves assessing multiple retorting processes, including two processes that have been proven at commercial scale. Also under evaluation is the Eco-Shale process developed by Red Leaf Resources Inc. ("Red Leaf"), a private oil shale and technology company. Red Leaf's principal assets include the Eco-Shale process to recover oil from shale in addition to oil shale leases in the state of Utah. Questerre owns approximately 6% of the equity capital of Red Leaf and licensing rights to their technology.

In conjunction with the assessment of retorting processes, the Company has commissioned and finalized three engineering studies for the mining, preparation of ore and upgrading of the produced oil and other products. Two additional studies for marketing the finished products and infrastructure, including utilities, are scheduled for completion in 2017. The Company anticipates incorporating the results from these studies in a subsequent update of its Jordan Resource Assessment.

The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data available at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that additional data and analysis available subsequent to the date of the estimates may necessitate revision. These revisions may be material. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The significant positive factors for estimating these resources include good well-spaced core, continuous regular resource and low structural complexity. The significant negative factors for these estimates include the coarse grid of well control reflecting the early stage nature of the project and the unknown nature of MFA quality control on the Ministry drilled cores.

In 2017, the Company plans to relinquish its rights to its interest in approximately 24,900 net acres in the Pasquia Hills area of east central Saskatchewan that overlie an identified oil shale deposit.

Corporate

The Company completed two private placements in 2016 for gross proceeds of $12.20 million.

In July 2016, the Company issued 26.39 million flow-through units for gross proceeds of approximately $4.75 million (the "Flow-Through Placement"). Each flow-through unit consists of one Common Share issued on a "flow-through" basis and one-half of one non-flow-through Common Share purchase warrant. Each whole warrant will entitle the holder to purchase one additional non-flow-through Common Share at a price of $0.20 for a period of 18 months from closing.

The gross proceeds of the Flow-Through Placement were used by the Company, pursuant to the provisions of the *Income Tax Act* (Canada), to incur eligible Canadian development expenses ("Qualifying Expenditures") from the closing date and until December 31, 2016 on Questerre's properties. The Company incurred and renounced the Qualifying Expenditures to subscribers of the Flow-Through Units for the fiscal year ended December 31, 2016.

In November 2016, the Company completed a private placement of 15.2 million Common Shares at a price of $0.49 per Common Share for gross proceeds of approximately $7.4 million.

In February 2017, the Company completed a private placement of 30.8 million Common Shares at a price of $0.79 per Common Share for gross proceeds of approximately $24 million.

In March 2017, in connection with the private placement completed by the Company in November 2016, the Company completed a subsequent private placement of 1.4 million Common Shares at a price of $0.49 per Common Share for gross proceeds of $0.7 million.

Following a review conducted in the fourth quarter of 2016, effective February 2017, the Company's credit facilities with a Canadian chartered bank were reduced to $23 million from $30 million as established in the third quarter of 2016. The credit facilities consist of a revolving operating demand loan. Any borrowings under the facilities, except letters of credit, are subject to interest at the bank's prime interest rate and applicable basis point margins based on the ratio of debt to cash flow, measured quarterly.

The facilities are secured by a revolving credit agreement, a debenture including a first floating charge over all assets of the Company and a general assignment of book debts. The next scheduled review of these credit facilities is in the second quarter of 2017.

Drilling Activities

In 2016, Questerre participated in the drilling of three (0.75 net) wells in the Kakwa-Resthaven area. Two (0.5 net) wells were placed on production in 2016, and one (0.25 net) will be completed and will be placed on production in the second quarter of 2017.

Production

	2016			2015		
	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)
Saskatchewan	**209**	**-**	**209**	201	-	201
Alberta	**547**	**3,360**	**1,107**	627	3,932	1,283
Manitoba	**45**	**-**	**45**	85	-	85
British Columbia	**-**	**74**	**12**	-	80	13
	801	**3,434**	**1,373**	913	4,012	1,582

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

With Kakwa representing approximately 75% of corporate volumes and Questerre's selective participation in the 2016 drilling program, reduced volumes from this area contributed to lower production over the prior year.

The Company's oil and liquids production represents light crude oil and natural gas liquids, and natural gas production represents primarily shale gas. The oil and liquids weighting remained unchanged at 58%, largely reflecting the approximately 50/50 split between liquids, primarily condensate and natural gas from Kakwa. The weighting also reflects the crude oil production from Saskatchewan and Manitoba which, in aggregate, declined over the prior year due to natural declines. The Company anticipates this decline could moderate with the workover and optimization work underway in Antler and in Manitoba.

As a result of its participation in the joint venture drilling program at Kakwa, the Company expects its production to increase in 2017.

2016 Financial Results

Petroleum and Natural Gas Sales

	2016			2015		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Saskatchewan	**$ 3,968**	**$ -**	**$ 3,968**	$ 4,114	$ -	$ 4,114
Alberta	**9,148**	**3,152**	**12,300**	11,574	4,620	16,194
Manitoba	**796**	**-**	**796**	1,644	-	1,644
British Columbia	**7**	**49**	**56**	-	63	63
	$ 13,919	**$ 3,201**	**$ 17,120**	$ 17,332	$ 4,683	$ 22,015

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Petroleum and natural gas revenue declined by 22% over the prior year due to lower commodity prices and production volumes.

Pricing

	2016	2015
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	2.16	2.73
Crude Oil - Canadian Light Sweet Blend ($/bbl)	54.28	58.68
Realized prices:		
Natural Gas ($/Mcf)	2.55	3.26
Crude Oil and Natural Gas Liquids ($/bbl)	47.51	51.75

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Crude oil prices continued their decline from the prior year with the benchmark West Texas Intermediate ("WTI") averaging US$43/bbl in 2016 compared to US$48.76/bbl in 2015.

Prices in the first quarter fell to their lowest level in 13 years on concerns about rising exports from Iran after the lifting of sanctions, onshore oil storage reaching capacity and the impact of a slowing Chinese economy on demand. Despite concerns about an increase in oil directed rigs in the US in the second half of the year and record production from Saudi Arabia and Russia, the agreement by OPEC to cut production in the fourth quarter materially improved prices by year-end. Prices in Canada benefitted from a stronger US dollar and narrower differential. On average, the differential between WTI and the benchmark Canadian Light Sweet blend ("MSW") declined from US$1.46/bbl to US$0.25/bbl in 2016.

Realized prices for Questerre's oil and liquids track the MSW benchmark with condensate generally receiving a premium to this price. This is offset by the materially lower prices for other natural gas liquids, particularly propane.

Natural gas prices declined more nominally in 2016 with the benchmark Henry Hub averaging US$2.48/MMBtu compared to an average price of US$2.68/MMBtu in 2015.

Despite reductions in drilling for liquids-rich resource plays, supply, particularly from the Marcellus and Utica shale in the northeast US, remain strong. This was compounded by slower than expected growth in demand for industrial and power usage, in part due to the growth of renewables for power generation. In Canada, high storage levels and limited access to Eastern markets resulted in a significant increase in the differential with the Henry Hub price. The differential averaged US$0.85/Mcf in 2016 compared to US$0.52/Mcf in 2015.

Higher heat content production from Kakwa contributed to a realized price of $2.55/Mcf in 2016 (2015: $3.26/Mcf) compared to an average AECO price of $2.16/Mcf (2015: $2.73/Mcf).

Royalties

($ thousands)		2016		2015
Alberta	$	545	$	816
Saskatchewan		294		213
Manitoba		97		217
British Columbia		-		-
	$	936	$	1,246
% of Revenue:				
Alberta		4%		5%
Saskatchewan		7%		5%
Manitoba		12%		13%
British Columbia		0%		0%
Total Company		5%		6%

Mirroring the decline in revenue, gross royalties decreased from $1.25 million to $0.94 million in 2016. As a percentage of revenue, royalties decreased marginally from 6% in 2015 to 5% in 2016.

The decrease is partially due to the lower overall rate on production from Kakwa which accounts for the majority of production from Alberta. The lower rate is attributable to the higher credits for processing the Crown's share of production through the Company's facilities. Production in Kakwa benefits from several incentive programs including the New Well Royalty Rate and the Natural Gas Deep Drilling Program that provides for royalties of up to 5%. These will remain in effect for a period of 10 years from the commencement of the Modernized Royalty Framework ("MRF"). Under the MRF, effective January 1, 2017, Crown incentive programs will be replaced with a capital cost allowance, with initial royalty rates of 5% of gross revenue until cumulative revenue reaches a certain threshold that reflects the total vertical depth, the total lateral length and the total proppant placed for the well. Thereafter, the well will move to post payout status with sliding scale royalties based on product type and commodity price. Once the well's production rate drops to a mature rate, the royalty rate will decrease to mitigate higher fixed costs.

Operating Costs

($ thousands)		2016		2015
Alberta	$	**6,142**	$	6,226
Saskatchewan		**1,105**		1,313
Manitoba		**301**		341
British Columbia		**104**		187
	$	**7,652**	$	8,067
$/boe:				
Alberta		**15.16**		13.28
Saskatchewan		**14.44**		17.99
Manitoba		**18.26**		10.98
British Columbia		**23.67**		39.43
Total Company		**15.23**		13.97

Driven by the lower production volumes in the year, operating costs decreased to $7.65 million from $8.07 million in 2015.

On a unit of production basis, operating costs averaged 9% higher in 2016 at $15.23/boe from $13.97/boe in 2015. In Alberta, with fixed costs representing over two thirds of operating costs at Kakwa in 2016, the allocation of these costs to lower production volumes resulted in an increase, on a boe basis, over the prior year. Additionally, 20% of these fixed costs relate to chemical sweetening. It is anticipated these costs will decrease materially with the installation of the regenerative amine system in the second quarter of 2017.

Similarly, in Saskatchewan fixed costs represent the majority of operating costs. With lower fixed operating costs in 2016, specifically workovers, the costs on a boe basis decreased over 2015.

General and Administrative Expenses

($ thousands)		2016		2015
General and administrative expenses, gross	$	**3,735**	$	4,938
Capitalized expenses and overhead recoveries		**(974)**		(1,392)
General and administrative expenses, net	$	**2,761**	$	3,546

Gross general and administrative expenses (“G&A”) in 2016 declined by 24% to $3.74 million from $4.94 million in the prior year.

The decrease reflects the corporate restructuring measures implemented over the past two years, including reductions in personnel, salaries and directors’ fees. The lower corporate activity levels and lower personnel costs were also responsible for the reduction in capitalized expenses and overhead recoveries.

Depletion, Depreciation, Impairment, Lease Expiries and Accretion

For the year ended December 31, 2016, the Company reported depletion and depreciation expense of $8.86 million compared to $9.73 million in 2015. The lower expense reflects the lower production in the current year. On a per unit basis, depletion increased to $17.62/boe from $16.85/boe in 2015 with higher production volumes in the current year from cash generating units (“CGUs”) with higher finding and development costs.

At December 31, 2016, the Company reviewed the carrying amounts of its property, plant and equipment and exploration and evaluation assets for indicators of impairment such as changes in future prices, future costs and reserves.

Based on this review, the Company's Antler, Manitoba, Vulcan, and Other Alberta CGUs were tested for impairment in accordance with the Company's accounting policy. The recoverable amount of the CGUs was estimated based on the fair value less costs of disposal ("FVLCD") using a discounted cash flow model. Based on the assessment, for the year ended December 31, 2016, the Company recorded an impairment loss of $0.47 million which relates to its Vulcan and Other Alberta CGUs. The factor that led to the impairment was a reduction in forecasted commodity prices.

The Company reviewed the carrying value of its Quebec CGU in light of the introduction of new hydrocarbon legislation in the province in 2016 and an independent assessment of its natural gas resources in Quebec as of December 31, 2016. Based on the Quebec Resource Assessment, the estimated fair value of these assets using a 10% discount rate is $258 million. As a result, the Company recognized a reversal of the impairment loss of $23.50 million recorded in 2015 for these assets.

Including the reversal of the impairment loss above and the impairment loss of $0.47 million, in 2016, the Company recorded a net reversal of impairment of $22.93 million. This amount also includes an impairment loss of $0.1 million recognized relating to the Company's investments. At December 31, 2015, an impairment loss of $18.70 million was recognized relating to the Company's investments. This amount in 2015 represented the difference between the carrying value of its investment in Red Leaf and its estimated fair value. The estimated fair value was determined using the net asset value method. The Company recorded $15.51 million of the impairment in net loss and $2.67 million in other comprehensive loss in 2015.

For the year ended December 31, 2016, the Company recorded an expense of $17.84 million related to upcoming lease expiries at Pasquia Hills and Wapiti where the Company has no future plans for development (2015: $3.13 million).

Share Based Compensation

Pursuant to the Company's stock option plan, an optionee may request that the Company purchase all or any part of the then vested options of the optionee for an amount equal to the market price of the Common Shares less the exercise price of the option shares. Notwithstanding the foregoing, the Company may, at its sole discretion, decline to accept and, accordingly, has no obligations with respect to the exercise of this put right at any time. Once the options are cash settled, the options are cancelled.

In December 2015, the Company changed the accounting for its stock based compensation awards to assume that options will be equity settled instead of cash settled. The change was made to reflect the settlement history of the options and the Company's intent to only settle options in equity in the future. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options is recorded as an increase in Common Shares with a corresponding reduction in contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

The Company recorded stock based compensation expense of $0.12 million for the year ended December 31, 2016. For the prior year, the Company recorded a recovery of $0.05 million.

Deferred Taxes

The Company reported a deferred tax expense of $0.45 million for 2016 compared to an expense of $2.12 million for the prior year.

The expense reflects the increase in its valuation allowance for its deferred tax asset at year end. In 2016, the Company assessed the recoverability of this asset using the estimate of before tax cash flows associated with its proved reserves using escalating pricing and future development costs as outlined in its independent reserve report, including an estimate of applicable G&A costs associated with these reserves. Questerre had sufficient tax pools to offset taxable income in 2016.

Other Income and Expenses

Changes to the fair value of the Company's risk management contracts are recorded through net profit or loss.

For the Company's outstanding risk management contracts at December 31, 2016, the unrealized loss recorded for the year ended December 31, 2016 was $1.53 million (2015: $0.33 million). For the Company's settled risk management contracts at December 31, 2016, the realized gain recorded for the year ended was $1.33 million (2015: $0.80 million).

Questerre reported interest expense of $0.91 million for the year ended December 31, 2016 and $1.49 million for the prior year. The expense primarily relates to the interest on its credit facilities with a Canadian chartered bank. In 2015, the expense primarily related to the interest on an outstanding joint venture billing and borrowings under its credit facilities.

The Company recorded a loss on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $0.01 million for the year ended December 31, 2016 (2015: gain of $2.42 million). The changes are due to fluctuations in the exchange rate relating to its US dollar investments.

Total Comprehensive Income (Loss)

Questerre's total comprehensive income was $0.10 million for 2016 compared to a loss of $73.45 million in 2015. The Company's change in total comprehensive income (loss) is attributable mainly to the reversal of the impairment expense compared to the prior year.

Net Income (Loss) Per Share

Questerre's basic net income per share increased to nil per share from a loss of $0.28 per share in 2015. Questerre's net income was $0.17 million in 2016 and a loss of $73.53 million in 2015.

Capital Expenditures

($ thousands)		2016		2015
Alberta	$	**11,909**	$	18,372
Saskatchewan		**540**		526
Manitoba		**39**		-
Jordan		**1,260**		825
Quebec		**470**		172
British Columbia		**-**		629
Corporate		**-**		-
		14,218		20,524
Dispositions		**-**		-
Total	**$**	**14,218**	$	20,524

In 2016, Questerre incurred capital expenditures of $14.22 million as follows:

- $11.91 million was invested in Alberta to participate in the drilling and completion of three (0.75 net) wells targeting condensate-rich natural gas from the Montney and related infrastructure costs.
- $0.54 million was invested in Saskatchewan to optimize production from wells that resulted in increased reserves.
- $1.26 million was invested in Jordan to assess the Company's oil shale acreage.

Questerre incurred net capital expenditures of $20.52 million in 2015 as detailed below

- In Alberta, the Company invested $18.37 million to participate in the drilling of one (0.25 net) well and complete six (1.5 net) wells targeting condensate-rich natural gas from the Montney and for infrastructure related costs.
- $0.53 million was invested in Saskatchewan to workover existing wells that resulted in increased reserves.
- $0.83 million was invested in Jordan to assess the Company's oil shale acreage.

Liquidity and Capital Resources

The Company's objectives when managing its capital are firstly to maintain financial liquidity, and secondly to optimize the cost of capital at an acceptable risk to sustain the future development of the business.

In February 2017, the Company's credit facilities were renewed at $23 million from $30 million at the last scheduled review. At December 31, 2016, $22.9 million (December 31, 2015: $14.54 million) was drawn on the credit facility and the Company is in compliance with all its covenants under the credit facilities. As a consequence of the foregoing, Management does not believe there is a reasonably foreseeable risk of non-compliance with its credit facilities. Under the terms of the credit facility, the Company has provided a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability (See Note 13 to the Financial Statements)) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2016 was 2.47 and the covenant was met.

The size of the credit facilities is determined by, among other things, the Company's current reserve report, results of operations and forecasted commodity prices. The next scheduled review is expected to be completed in the second quarter of 2017.

The credit facilities are a demand facility and can be reduced, amended or eliminated by the lender for reasons beyond the Company's control. Should the credit facilities be reduced or eliminated, the Company would need to seek alternative credit facilities or consider the issuance of equity to enhance its liquidity.

Questerre had a working capital deficit, including amounts due under its credit facilities, of $17.02 million at December 31, 2016, as compared to a deficit of $21.48 million at December 31, 2015. Management believes that with its private placements completed in the first quarter of 2017 for gross proceeds of over $25 million, expected positive operating cash flows from operations and current credit facilities, the Company should generate sufficient cash flows and have access to sufficient financial liquidity to meet its foreseeable obligations in the normal course of operations.

Questerre anticipates an improvement in commodity prices, which is expected to improve cash flow and reduce the working capital deficit to the extent adjusted funds flow from operations exceeds planned capital expenditures. On an ongoing basis, the Company will manage where possible future capital expenditures to maintain liquidity (See "Commitments"). However, it cannot provide any assurance that sufficient cash flows will be generated from operating activities to reduce its working capital deficiency and to carry out its planned capital expenditure program. The Company intends to invest up to 90% of the 2017 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2016. It anticipates that, as a result, reserves associated with wells not drilled in 2017 will remain in the proved undeveloped category.

For a detailed discussion of the risks and uncertainties associated with the Company's business and operations, see the Risk Management section of the Company's 2016 Annual MD&A and the AIF.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2016 and 2015 was $6.72 million and $8.96 million, respectively. The Company realized lower net revenue in 2016, which was partially offset by changes in non-cash working capital.

Cash Flow used in Investing Activities

Cash flow used in investing activities decreased to $19.68 million in 2016 from $34.16 million in 2015. For the year ended December 31, 2016, the Company incurred capital expenditures of $14.22 million compared to $20.52 million for the same period in 2015. The lower net capital expenditures were mainly due to lower investment activity in the Kakwa-Resthaven area.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities was $20.89 million in 2016 and $14.54 million in 2015. The increase in 2016 reflects the drawdowns under the Company's credit facilities and the proceeds from the private placements completed in the year. In 2015, the amount relates only to the drawdowns under the credit facilities.

Share Capital

The Company is authorized to issue an unlimited number of Common Shares. The Company is also authorized to issue an unlimited number of Class "B" common voting shares and an unlimited number of preferred shares, issuable in one or more series. At December 31, 2016, there were no Class "B" common voting shares or preferred shares outstanding.

The following table provides a summary of the outstanding Common Shares and options as at the date of the MD&A and the current and preceding year-ends.

(thousands)	March 24, 2017	December 31, 2016	December 31, 2015
Common Shares	345,118	308,274	264,932
Stock Options	14,783	14,856	-
Warrants	8,504	13,124	19,982
Weighted average Common Shares			
Basic		278,662	264,932
Diluted		280,410	264,932

A summary of the Company's stock option activity during the years ended December 31, 2016 and 2015 follows:

	December 31, 2016		December 31, 2015	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	19,982	$0.72	17,792	$1.96
Granted	4,100	0.18	10,532	0.29
Forfeited	(4,289)	0.47	(2,819)	1.10
Expired	(3,260)	1.85	(5,523)	3.68
Exercised	(1,677)	0.60	-	-
Outstanding, end of period	14,856	$0.41	19,982	$0.72
Exercisable, end of period	5,939	$0.55	6,808	$0.97

Commitments

A summary of the Company's net commitments at December 31, 2016 follows:

($ thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation, Marketing and Processing	$ 4,728	$ 4,728	$ 3,990	$ 3,990	$ 3,990	$ 19,952	$ 41,378
Office Leases	112	99	99	90	-	-	400
	$ 4,840	$ 4,827	$ 4,089	$ 4,080	$ 3,990	$ 19,952	$ 41,779

In the fall of 2013, the Company entered into a series of take or pay agreements for the processing, transportation, fractionating and marketing of 20 MMcf/d of raw gas and associated liquids production in the Kakwa-Resthaven area (the "Infrastructure Contracts"). In December 2014, the Company assigned a 57.5% interest in the Infrastructure Contracts on a permanent basis to third parties. Concurrently, the Company also assigned an 18.75% interest in the Infrastructure Contracts on a temporary basis to a third party until December 2016.

Questerre has no capital commitments in 2017. In order to maintain its capacity to execute its business strategy, the Company expects that it will need to continue the development of its producing assets. There will also be expenditures in relation to G&A and other operational expenses. These expenditures are not yet commitments, but Questerre expects to fund such amounts primarily out of adjusted funds flow from operations and its existing credit facilities.

Risk Management

Companies engaged in the petroleum and natural gas industry face a variety of risks. For Questerre, these include risks associated with exploration and development drilling as well as production operations, commodity prices, exchange and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates and government regulations could have an impact on the Company's future operating results and/or financial condition. While management realizes that all the risks may not be controllable, Questerre believes that they can be monitored and managed. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF and Note 6 to the audited consolidated financial statements for the year ended December 31, 2016.

A significant risk for Questerre as a junior exploration company is access to capital. The Company attempts to secure both equity and debt financing on terms it believes are attractive in current markets. Management also endeavors to seek participants to farm-in on the development of its projects on favorable terms. However, there can be no assurance that the Company will be able to secure sufficient capital if required or that such capital will be available on terms satisfactory to the Company.

As future capital expenditures will be financed out of adjusted funds flow from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry, and the Company's securities in particular. To the extent that external sources of capital become limited or unavailable, or available but on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected. Based on current funds available and expected adjusted funds flow from operations, the Company believes it has sufficient funds available to fund its projected capital expenditures. However, if adjusted funds flow from operations is lower than expected, or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Questerre faces a number of financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies.

The Company uses the following guidelines to address financial exposure:

- Internally generated cash flow provides the initial source of funding on which the Company's annual capital expenditure program is based.
- Equity, including flow-through shares, if available on acceptable terms, may be raised to fund acquisitions and capital expenditures.
- Debt may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled.
- Farm-outs of projects may be arranged if management considers that a project requires too much capital or where the project affects the Company's risk profile.

Credit risk represents the potential financial loss to the Company if a customer or counterparty to a financial instrument fails to meet or discharge their obligation to the Company. Credit risk arises from the Company's receivables from joint venture partners and oil and gas marketers. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Credit risk also arises from the Company's cash and cash equivalents. In the past, the Company manages credit risk exposure by investing in Canadian banks and credit unions. Management does not expect any counterparty to fail to meet its obligations.

Poor credit conditions in the industry may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner if possible.

Substantially all of the accounts receivable are with oil and natural gas marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable counterparties and partners.

Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major oil and natural gas marketing and infrastructure companies and the Company has not experienced any credit loss relating to these sales to date.

Receivables from joint venture partners are typically collected within one to three months after the joint venture bill is issued. The Company mitigates this risk by obtaining pre-approval of significant capital expenditures.

The Company has issued and may continue in the future to issue flow-through shares to investors. The Company uses its best efforts to ensure that qualifying expenditures of Canadian Exploration Expense ("CEE") are incurred in order to meet its flow-through obligations. However, in the event that the Company incurs qualifying expenditures of Canadian Development Expense ("CDE") or has CEE expenditures reclassified under audit by the Canada Revenue Agency, the Company may be required to liquidate certain of its assets in order to meet the indemnity obligations under the flow-through share subscription agreements.

Exploration and development drilling risks are managed through the use of geological and geophysical interpretation technology, employing technical professionals and working in areas where those individuals have experience. For its non-operated properties, the Company strives to develop a good working relationship with the operator and monitors the operational activity on the property. The Company also carries appropriate insurance coverage for risks associated with its operations.

The Company may use financial instruments to reduce corporate risk in certain situations. Questerre's hedging policy is up to a maximum of 40% of total production at management's discretion.

As at December 31, 2016, the Company had the following outstanding commodity risk management contract in place:

Risk Management Contract	Volumes	Average Price	Term	Fair Value Liability *($ thousands)*
AECO call option sale	3,000 GJ/d	$2.70/GJ	Jan. 1, 2017 - Dec. 31, 2017	764
WTI Nymex call option sale	200 bbls/d	$80/bbl	Jan. 1, 2017 - Dec. 31, 2017	353

Please Refer to Note 6 e) of the audited consolidated financial statements for the year ended December 31, 2016.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases of emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations, which can affect the location and operation of wells and facilities, and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures, and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders. The Company mitigates the potential financial exposure of environmental risks by complying with the existing regulations and maintaining adequate insurance. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF.

Critical Accounting Estimates

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. These estimates and judgments have risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Petroleum and Natural Gas Reserves and Resources

All of Questerre's petroleum and natural gas reserves and resources are evaluated and reported on by independent petroleum engineering consultants in accordance with NI 51-101 and the COGE Handbook. For further information, please refer to "Statement of Reserves Data and Other Oil and Gas Information" in the AIF.

The estimation of reserves and resources is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves and resources will change to reflect updated information. Reserve and resource estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices. These estimates are evaluated by independent reserve engineers at least annually.

Proven and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. If probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves and there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Reserve and resource estimates impact a number of the areas, in particular, the valuation of property, plant and equipment, exploration and evaluation assets and the calculation of depletion.

Cash Generating Units

A CGU is defined as the lowest grouping of assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include geography and the manner in which management monitors and makes decisions about its operations.

Impairment of Property, Plant and Equipment, Exploration and Evaluation and Goodwill

The Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Determining if there are facts and circumstances present that indicate that carrying values of the assets may not be recoverable requires management's judgment and analysis of the facts and circumstances.

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the FVLCD. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, the discount rate, future operating and development costs and recent land transactions. Changes to these assumptions will affect the recoverable amounts of the CGUs and may require a material adjustment to their related carrying value.

Goodwill is the excess of the purchase price paid over the fair value of the net assets acquired. Since goodwill results from purchase accounting, it is imprecise and requires judgment in the determination of the fair value of assets and liabilities. Goodwill is assessed for impairment on an operating segment level based on the recoverable amount for each CGU of the Company. Therefore, impairment of goodwill uses the same key judgments and assumptions noted above for impairment of assets.

Asset Retirement Obligation

Determination of the Company's asset retirement obligation is based on internal estimates using current costs and technology in accordance with existing legislation and industry practice and must also estimate timing, a risk-free rate and inflation rate in the calculation. These estimates are subject to change over time and, as such, may impact the charge against profit or loss. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a risk-free rate. The associated abandonment and retirement costs are capitalized as part of the carrying amount of the related asset. The capitalized amount is depleted on a unit of production basis in accordance with the Company's depletion policy. Changes to assumptions related to future expected costs, risk-free rates and timing may have a material impact on the amounts presented.

Share Based Compensation

The Company has a stock option plan enabling employees, officers and directors to receive Common Shares or cash at exercise prices equal to the market price or above on the date the option is granted. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value using the Black-Scholes option pricing model. The assumptions used in the calculation are: the volatility of the stock price, risk-free rates of return and the expected lives of the options. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Changes to assumptions may have a material impact on the amounts presented.

Income Tax Accounting

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the Company's estimate, the ability of the Company to realize the deferred tax assets could be impacted.

The Company has revised its estimate related to deferred tax assets in the year. As at December 31, 2016, the recoverability of deferred tax assets was assessed using proved reserves including an estimate of G&A associated with the assets.

The determination of the Company's income and other tax assets or liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset or liability may differ significantly from that estimated and recorded by management.

Investment in Red Leaf

Questerre has investments in certain private companies, including Red Leaf, which it classifies as an available for sale financial instrument and carries at fair value. The Company measures the fair market value of Red Leaf by reference to recent corporate transactions of Red Leaf, or in the absence of such transactions, other valuation techniques such as the net asset value approach.

The Company also assesses factors that might indicate that the corporate transaction price might not be representative of fair value at the measurement date. These factors include significant changes in the performance of the investee compared with budgets, plans or milestones, changes in management or strategy and significant changes in the price of oil. Considerable judgment is required in measuring the fair value of the Company's investment in Red Leaf, which may result in material adjustments to its related carrying value.

Accounting Standards Changes

Changes in Accounting Policies for 2016

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2016.

Future Accounting Pronouncements

The following standards and interpretations have not been illustrated as they will only be applied for the first time in future periods. They may result in consequential changes to the accounting policies and other note disclosures. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements.

IFRS 16 Leases

On January 13, 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded. IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 Revenue From Contracts With Customers has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements.

IFRS 15 Revenue From Contracts With Customers

In May 2014, the IASB published IFRS 15 Revenue From Contracts With Customers ("IFRS 15") replacing IAS 11 Construction Contracts, IAS 18 Revenue and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser.

The new standard is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on its consolidated financial statements.

IFRS 9 Financial Instruments

In February 2014, the IASB tentatively decided to require an entity to apply IFRS 9 Financial Instruments for annual periods beginning on or after January 1, 2018. The full impact of the standard on the Company's financial statements will not be known until changes are finalized. Early adoption is permitted.

Design and Evaluation of Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Questerre is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings"("NI 52-109") and is required to make specific disclosures with respect to NI 52-109 as follows:

- The Company has designed and evaluated the effectiveness of Disclosure Controls and Procedures ("DC&P"). The President and Chief Executive Officer and the Chief Financial Officer have concluded that DC&P are designed appropriately and are operating effectively as at December 31, 2016.
- The Chief Executive Officer and the Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the Company's ICFR as at December 31, 2016 and have concluded that such ICFR have been designed appropriately and are operating effectively.
- The Company reports that no changes were made to ICFR during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect the Company's ICFR.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Fourth Quarter 2016 Results

Questerre's cash from operating activities increased to $2.70 million for the quarter ended December 31, 2016 from $1.78 million for the same period in 2015. This is attributable to the increase in non-cash working capital, which offsets the lower petroleum and natural gas revenue. The decrease in adjusted funds flow from operations is due to lower petroleum and natural gas revenue in the period compared to the prior year.

Petroleum and natural gas revenue decreased from $5.31 million for the three months ended December 31, 2015 to $4.57 million for the same period in 2016. Although prices improved over the year, production volumes were lower in 2016. The Company's realized price for oil and natural gas liquids was $51.12/bbl for the fourth quarter of 2016 compared with $48.08/bbl for the fourth quarter of 2015. In the fourth quarter, production decreased from 1,648 boe/d in 2015 to 1,261 boe/d in 2016. Production volumes in 2016 declined at the Company's Kakwa-Resthaven area where no new wells were brought on production since the third quarter of the year. Moreover in 2016, the Company only brought on-stream 2 (0.5 net) wells in this area compared to 6 (1.5 net) wells in 2015.

Operating costs were $1.67 million or $14.38/boe for the three months ended December 31, 2016 compared to $2.22 million or $14.69/boe for the same period in 2015. The decrease in operating costs is mainly due to lower production in 2015. On a per unit basis, operating costs remained relatively unchanged.

The Company recorded a net reversal impairment expense of $22.93 million for the three months ended December 31, 2016 compared to impairment expense of $47.17 million for the same period in 2015. This amount in 2016 included the reversal of an impairment charge of $23.50 million associated with its Quebec exploration and evaluation assets based on the passage of new hydrocarbon legislation in the province and an independent assessment of its resources in the province. In 2015, impairment charges, included $18.15 million for its property, plant and equipment, $23.50 million relating to its Quebec exploration and evaluation assets and $5.7 million for its investments.

Total comprehensive income for the three months ended December 31, 2016 was $3.67 million compared to a loss of $55.96 million for the same period in 2015. The increase in comprehensive income from a loss in 2015 is due to the reversal of the impairment expense partially offset by higher lease expiry expense.

Capital expenditures were $5.26 million and $1.01 million for the three months ended December 31, 2016 and 2015, respectively. In 2016, capital expenditures included $4.55 million for its Kakwa-Resthaven assets and $0.20 million for its Antler assets. In 2015, capital expenditures included $0.52 million for its Jordan assets, $0.33 million for its Kakwa-Resthaven assets and $0.11 million for its Antler assets.

Quarterly Financial Information

($ thousands, except as noted)	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016
Production (boe/d)	**1,261**	1,275	1,422	1,538
Average Realized Price ($/boe)	**39.43**	34.91	34.17	28.79
Petroleum and Natural Gas Sales	**4,574**	4,095	4,423	4,029
Adjusted Funds Flow from Operations	**1,943**	1,447	1,916	1,740
Basic and Diluted ($/share)	**0.01**	0.01	0.01	0.01
Net Profit (Loss)	**3,674**	(1,007)	(2,173)	(325)
Basic and Diluted ($/share)	**0.01**	-	(0.01)	-
Capital Expenditures, net of acquisitions and dispositions	**5,260**	4,060	741	4,158
Working Capital Surplus (Deficit)	**(17,019)**	(21,250)	(23,075)	(24,044)
Total Assets	**177,761**	165,109	161,721	163,547
Shareholders' Equity	**139,660**	127,895	125,028	127,134
Weighted Average Common Shares Outstanding				
Basic (thousands)	**293,470**	283,494	264,932	264,932
Diluted (thousands)	**308,017**	283,494	264,932	264,932

($ thousands, except as noted)	December 31, 2015	September 30, 2015 [1]	June 30, 2015 [1]	March 31, 2015 [1]
Production (boe/d)	1,648	1,934	1,480	1,257
Average Realized Price ($/boe)	35.03	36.69	44.90	36.49
Petroleum and Natural Gas Sales	5,311	6,528	6,048	4,128
Adjusted Funds Flow from Operations	2,269	3,182	3,067	1,308
Basic and Diluted ($/share)	0.01	0.01	0.01	-
Net Profit (Loss)	(56,044)	(18,169)	1,333	(656)
Basic and Diluted ($/share)	(0.21)	(0.07)	0.01	-
Capital Expenditures, net of acquisitions and dispositions	1,014	6,213	5,095	8,203
Working Capital Surplus (Deficit)	(21,478)	(21,334)	(18,202)	(16,165)
Total Assets	161,894	217,794	233,627	230,905
Shareholders' Equity	127,453	183,151	202,220	201,147
Weighted Average Common Shares Outstanding				
Basic (thousands)	264,932	264,932	264,932	264,932
Diluted (thousands)	264,932	264,932	264,936	264,934

[1] Certain figures have been revised. Refer to note 2 of the December 31, 2015 financial statements.

The general trends over the last eight quarters are as follows:

- Adjusted funds flow from operations has generally declined due to lower production levels and a general decrease in average realized commodity prices.
- Production has decreased to 1,261 boe/d for the three months ended December 31, 2016 as compared with 1,648 boe/d for the same period in the prior year. Production has decreased over the most recent five quarters primarily due to the reduced capital investment in the Company's Kakwa-Resthaven assets as a result of lower commodity prices.
- The working capital deficit has grown as capital expenditures have been higher than the adjusted funds flow from operations. This has reduced in the last quarter as a result of the private placement completed in November 2016.
- Capital expenditures decreased in the last four quarters compared to the first four quarters due to a reduced capital program in light of lower commodity prices. The level of capital expenditures over the quarters has varied primarily due to the number of wells drilled and completed on the Kakwa-Resthaven asset.
- In the fourth quarter of 2016, shareholders' equity increased as a result of the equity issuance completed by the Company. Shareholders' equity has decreased in prior periods due to impairment charges recorded in the fourth quarters of 2014 and 2015 and the third quarter of 2015. The impairment charges relate to its property, plant and equipment and exploration and evaluation assets and its investment in Red Leaf.
- In September 2015 and December 2014 and 2015, the Company recorded a net loss per share due to impairment expenses.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2016.

Related Party Transactions

Other than indicated below, the Company did not engage in any related party transactions during the year ended December 31, 2016.

Certain directors and officers of the Company participated in the Flow-Through Placement, which constituted a "related party transaction" within the meaning of Multilateral Instrument 61-101 – *Protection of Minority Security Holders in Special Transactions* ("MI 61-101"). Questerre relied upon exemptions from the formal valuation and minority approval requirements of MI 61-101 based on a determination that the fair market value of the placement, insofar as it involved related parties, did not exceed 25% of the market capitalization of the Company.

Management's report

The consolidated financial statements of Questerre Energy Corporation were prepared by management in accordance with International Financial Reporting Standards. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Company's operations and that the Company's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, was appointed by a resolution of the shareholders to audit the consolidated financial statements of the Company and provide an independent opinion. They have conducted an independent examination of the Company's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with PricewaterhouseCoopers LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

Michael Binnion
President and Chief Executive Officer

Jason D'Silva
Chief Financial Officer

Calgary, Alberta, Canada
March 24, 2017

Independent Auditor's Report

To the Shareholders of Questerre Energy Corporation

We have audited the accompanying consolidated financial statements of Questerre Energy Corporation, which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015 and the consolidated statements of net profit or loss and comprehensive income or loss, changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Questerre Energy Corporation as at December 31, 2016 and December 31, 2015 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta

March 24, 2017

Consolidated Balance Sheets

($ thousands)	Note	December 31, 2016	December 31, 2015
Assets			
Current Assets			
Cash and cash equivalents	5	$ 8,275	$ 343
Accounts receivable	6	2,339	2,668
Current portion of risk management contracts	6	-	1,032
Deposits and prepaid expenses		626	582
		11,240	4,625
Investments	7	490	632
Property, plant and equipment	8	87,125	87,547
Exploration and evaluation assets	9	58,915	47,917
Goodwill		2,346	2,346
Deferred tax assets	10	17,645	18,827
		$ 177,761	$ 161,894
Liabilities			
Current Liabilities			
Accounts payable and accrued liabilities		$ 5,370	$ 10,529
Current portion of risk management contracts	6	1,117	-
Credit Facilities	13	22,888	14,542
		29,375	25,071
Risk management contracts	6	-	618
Asset retirement obligation	12	8,726	8,752
Share based compensation liability	11	-	-
		38,101	34,441
Shareholders' Equity			
Share capital	14	359,151	347,345
Contributed surplus		17,254	16,951
Accumulated other comprehensive income		138	209
Deficit		(236,883)	(237,052)
		139,660	127,453
		$ 177,761	$ 161,894

Commitments (note 19)

The notes are an integral part of these consolidated financial statements.

Signed on behalf of the Board of Directors

Dennis Sykora
Director

Bjorn Inge Tonnessen
Director

Consolidated Statements of Net Profit or Loss and Comprehensive Income or Loss

($ thousands, except per share amounts)	Note	For the years ended December 31, 2016	2015
Revenue			
Petroleum and natural gas sales	15	$ 17,120	$ 22,015
Royalties		(936)	(1,246)
Petroleum and natural gas revenue, net of royalties		16,184	20,769
Expenses			
Direct operating		7,652	8,067
General and administrative		2,761	3,546
Depletion and depreciation	8	8,861	9,730
Impairment of assets	7,8,9	(22,925)	66,490
Lease Expiries		17,838	3,130
Loss (gain) on risk management contracts	6	195	(468)
Share based compensation (recovery)	11	122	(54)
Accretion of asset retirement obligation	12	142	115
Interest expense		912	1,487
Other expense		12	139
Income (loss) before taxes		614	(71,413)
Deferred tax expense	10	445	2,121
Net Income (Loss)		169	(73,534)
Other Comprehensive Income (Loss), Net of Tax			
Items that may be reclassified subsequently to profit or loss:			
Gain (loss) on foreign exchange	7	(13)	2,422
Foreign currency translation adjustment		(30)	22
Reclass to net loss on write-down of investments	7	(28)	(2,363)
		(71)	81
Total Comprehensive Income (Loss)		$ 98	$ (73,453)
Net Loss per Share			
Basic and diluted	14	$ -	$ (0.28)

The notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Equity

($ thousands)	For the years ended December 31, 2016	2015
Share Capital		
Balance, beginning of year	$ 347,345	$ 347,345
Private Placements	11,279	-
Warrants exercised	1,006	-
Options exercised	15	-
Share issue costs (net of tax)	(494)	-
Balance, end of year	359,151	347,345
Contributed Surplus		
Balance, beginning of year	16,951	16,686
Reclassification of share based compensation	303	265
Balance, end of year	17,254	16,951
Accumulated Other Comprehensive Income		
Balance, beginning of year	209	128
Other comprehensive income (loss)	(71)	81
Balance, end of year	138	209
Deficit		
Balance, beginning of year	(237,052)	(163,518)
Net loss	169	(73,534)
Balance, end of year	(236,883)	(237,052)
Total Shareholders' Equity	$ 139,660	$ 127,453

The notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2016	2015
Operating Activities			
Net loss		$ 169	$ (73,534)
Adjustments for:			
Depletion and depreciation	8	8,861	9,730
Impairment of assets & lease expiries	7,8,9	(5,087)	69,620
Unrealized loss on risk management contracts	6	1,531	334
Share based compensation (recovery)	11	122	(54)
Accretion of asset retirement obligation	12	142	115
Deferred tax expense	10	445	2,121
Interest expense		912	1,487
Other items not involving cash		(32)	19
Abandonment expenditures	12	(18)	(60)
Adjusted funds flow from operations		7,045	9,778
Interest paid		(912)	(225)
Change in non-cash working capital	18	586	(596)
Net cash from operating activities		6,719	8,957
Investing Activities			
Property, plant and equipment expenditures	8	(3,301)	(2,241)
Exploration and evaluation expenditures	9	(10,917)	(18,283)
Change in non-cash working capital	18	(5,457)	(13,637)
Net cash used in investing activities		(19,675)	(34,161)
Financing Activities			
Proceeds from issue of share capital		13,218	-
Increase in credit facilities		32,246	33,767
Repayment of credit facilities		(23,900)	(19,225)
Share issue costs		(676)	-
Net cash from financing activities		20,888	14,542
Change in cash and cash equivalents		7,932	(10,662)
Cash and cash equivalents, beginning of year		343	11,005
Cash and cash equivalents, end of year		$ 8,275	$ 343

The notes are an integral part of these consolidated financial statements.

1. Reporting Entity

Questerre Energy Corporation ("Questerre" or the "Company") is actively involved in the acquisition, exploration and development of oil and gas projects, specifically, non-conventional projects such as tight oil, oil shale, shale oil and shale gas. The consolidated financial statements of the Company as at and for the years ended December 31, 2016 and 2015 comprise the Company and its wholly-owned subsidiaries in those periods owned. The Company wholly owns Questerre Energy Corporation/Jordan, which holds interests in the oil shale assets in Jordan.

Questerre is incorporated under the laws of the Province of Alberta and is domiciled in Canada. The address of its registered office is 1650, 801 Sixth Avenue SW, Calgary, Alberta.

2. Basis of Preparation

a) Statement of compliance

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Boards ("IASB"). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at March 24, 2017, the date the Board of Directors approved the statements.

b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for available for sale financial assets and financial assets classified as fair value through profit and loss which are measured at fair value with changes in fair value recorded in other comprehensive income or loss or profit or loss as disclosed in Note 3.

c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. The Company has a wholly-owned subsidiary with a functional currency of Jordanian Dinar.

d) Jointly controlled assets

The Company conducts many of its oil and gas production activities through jointly controlled operations. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

e) Use of estimates and judgments

The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. These estimates and judgments have risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Petroleum and natural gas reserves and resources

All of Questerre's petroleum and natural gas reserves and resources are evaluated and reported on by independent reserve engineers in accordance with the COGE Handbook and Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The estimation of reserves and resources is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves and resources will change to reflect updated information. Reserve and resource estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices. These estimates are evaluated by independent reserve engineers at least annually.

Proven and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. If probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves and there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Reserve and resource estimates impact a number of areas, in particular, the valuation of property, plant and equipment, exploration and evaluation assets and the calculation of depletion.

Refer to Note 8 & 9 for carrying amounts of property, plant and equipment, exploration and evaluation assets.

Cash generating units ("CGU")

A CGU is defined as the lowest grouping of assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include geography and the manner in which management monitors and makes decisions about its operations.

Refer to Note 8 for carrying amounts of property, plant and equipment.

Impairment of property, plant and equipment, exploration and evaluation and goodwill

The Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate carrying values of the assets may not be recoverable. Determining if there are facts and circumstances present that indicate that carrying values of the assets may not be recoverable requires management's judgment and analysis of the facts and circumstances.

The recoverable amounts of CGUs have been determined based on the higher of value in use ("VIU") and the fair value less costs of disposal ("FVLCD"). The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, the discount rate, future operating and development costs and recent land transactions. Changes to these assumptions will affect the recoverable amounts of CGUs and may require a material adjustment to their related carrying value.

Goodwill is the excess of the purchase price paid over the fair value of the net assets acquired. Since goodwill results from purchase accounting, it is imprecise and requires judgment in the determination of the fair value of assets and liabilities. Goodwill is assessed for impairment at an operating segment level based on the recoverable amount for each CGU of the Company. Therefore, impairment of goodwill uses the same key judgments and assumptions noted above for impairment of assets.

Refer to Note 8 for the sensitivity analysis related to impairments.

<u>Asset retirement obligation</u>

Determination of the Company's asset retirement obligation is based on internal estimates using current costs and technology in accordance with existing legislation and industry practice and must also estimate timing, a risk-free rate and inflation rate in the calculation. These estimates are subject to change over time and, as such, may impact the charge against profit or loss. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a risk-free rate. The associated abandonment and retirement costs are capitalized as part of the carrying amount of the related asset. The capitalized amount is depleted on a unit of production basis in accordance with the Company's depletion policy. Changes to assumptions related to future expected costs, risk-free rates and timing may have a material impact on the amounts presented.

Refer to Note 12 for the carrying amounts related to the asset retirement obligation.

<u>Share based compensation</u>

The Company has a stock option plan enabling employees, officers and directors to receive Common Shares or cash at exercise prices equal to the market price or above on the date the option is granted. The Company does not intend to cash settle these options in future periods. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value using the Black-Scholes option pricing model. The assumptions used in the calculation are: the volatility of the stock price, risk-free rates of return and the expected lives of the options. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Changes to assumptions may have a material impact on the amounts presented.

For further detail on carrying amounts and assumptions refer to Note 11.

Income tax accounting

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the Company's estimate, the ability of the Company to realize the deferred tax assets could be impacted.

The Company has revised its estimate of its deferred tax assets in the year. As at December 31, 2016, the recoverability of deferred tax assets was assessed using proved reserves with an estimate of general and administrative costs associated with these proved reserves.

The determination of the Company's income and other tax assets or liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset or liability may differ significantly from that estimated and recorded by management.

Refer to Note 10 for the carrying amounts related to deferred taxes.

Investment in Red Leaf Resources

Questerre has investments in certain private companies, including Red Leaf Resources Inc. ("Red Leaf"), which it classifies as an available for sale financial instrument and carries at fair value.

The Company measures the fair market value of Red Leaf by reference to recent corporate transactions of Red Leaf, or in the absence of such transactions, other valuation techniques such as the net asset value approach. The Company also assesses factors that might indicate that the corporate transaction price might not be representative of fair value at the measurement date. These factors include significant changes in the performance of the investee compared with budgets, plans or milestones, changes in management or strategy and significant changes in the price of oil. Considerable judgment is required in measuring the fair value of the Company's investment in Red Leaf, which may result in material adjustments to its related carrying value.

Refer to Note 7 for the carrying amounts and further detail on the recoverability related to the Company's investment in Red Leaf.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

a) Basis of consolidation

Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company 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 acquisition method of accounting is used to account for business combinations that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Contingent consideration is included in the cost of acquisitions at fair value. Directly attributable transaction costs are expensed in the current period and reported within general and administrative expenses. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit or loss.

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) Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized when the obligation specified in the contract is discharged, cancelled or expires.

Financial assets and liabilities are offset and the net amount is reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

The Company classifies its financial instruments in the following categories, at initial recognition, depending on the purpose for which the instruments were acquired.

Financial assets and liabilities at fair value through profit or loss

A financial asset or liability is classified in this category if it is held for trading. Derivatives are also included in this category unless they are designated as hedges. The Company has designated its risk management contracts in this category.

Available for sale

Available for sale investments are non-derivatives that are either designated in this category or not classified in any of the other categories. The Company has designated its investments in this category.

Available for sale investments are recognized initially at fair value plus transaction costs and are subsequently carried at fair value. Any unrealized gains or losses from remeasurement are recognized in other comprehensive income or loss. When an available for sale investment is sold or impaired, the accumulated gains or losses are moved from accumulated other comprehensive income or loss to profit or loss. Available for sale investments are classified as non-current, unless an investment matures within twelve months, or management expects to dispose of it within twelve months.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Company's loans and receivables are included in current assets due to their short-term nature. Loans and receivables are recognized initially at the amount expected to be received, less, when material, a discount to reduce loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less a provision for impairment.

Cash and cash equivalents include deposits held with banks, less outstanding cheques and short-term deposits with original maturities of one year or less.

Financial liabilities at amortized cost

Financial liabilities at amortized cost comprise credit facilities and accounts payable and accrued liabilities. Financial liabilities are initially recognized at the amount required to be paid, less, when material, a discount to reduce the payables to fair value. Subsequently, financial liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months.

c) Share capital

Common Shares are classified as equity. Incremental costs directly attributable to the issue of Common Shares are recognized as a deduction from equity, net of any tax effects.

d) Property, plant and equipment and exploration and evaluation assets

Recognition and measurement

Exploration and evaluation expenditures

Costs incurred prior to acquiring the legal rights to explore an area are recognized as exploration and evaluation expense in profit or loss.

Exploration and evaluation costs, including the costs of acquiring licenses, exploratory well expenditures, costs to evaluate the commercial potential of underlying resources and directly attributable general and administrative costs, are capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by exploration area pending determination of technical feasibility and commercial viability.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable based on several factors including the assignment of reserves. A review of each exploration license or field is carried out, at each reporting date, to ascertain whether technical feasibility and commercial viability has been achieved. Upon determination of technical feasibility and commercial viability, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment.

Every reporting period, the Company evaluates individually significant exploration and evaluation wells for impairment, if there are specific impairment indicators evident at the well level. If technical feasibility and commercial viability of the well is not established, the well costs are written off. For insignificant wells, overall exploration and evaluation well indicators are evaluated. If there are indicators of impairment, the wells are tested for impairment at the CGU level.

Development and production costs

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Cost includes all costs required to acquire developed or producing oil and gas properties and to develop oil and gas properties. Development and production assets are grouped into CGUs for impairment testing.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of the property, plant and equipment and are recognized net within gain (loss) on divestures in profit or loss.

Exchanges of properties are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured. When the exchange is at fair value, a gain or loss is recognized in profit or loss.

Other property, plant and equipment

Expenditures related to work-overs or betterments that improve the productive capacity or extend the life of an asset are capitalized. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depletion and depreciation

The net carrying value of development and production assets is depleted using the unit of production method based on estimated proven and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are evaluated by independent reserve engineers at least annually.

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the respective useful lives.

Depreciation methods and useful lives are reviewed at each reporting date.

e) Goodwill

Goodwill arises on the acquisition of businesses, subsidiaries, associates and joint ventures. Goodwill is measured at cost less accumulated impairment losses. Goodwill is not amortized.

f) Impairment

Non-financial assets

The carrying amounts of the Company's non-financial assets, other than deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated and compared to the carrying amount. For goodwill an impairment test is completed each year, or when any indication of impairment exists.

For the purpose of impairment testing, assets are grouped together into CGUs. Goodwill, for the purpose of impairment testing, is assessed for impairment on an operating segment basis. The Company has one operating segment, which is Canada. Exploration and evaluation assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their reclassification to producing assets.

The recoverable amount of an asset or a CGU is the greater of its VIU and FVLCD. FVLCD is determined using discounted future cash flows of proved and probable reserves using an after tax discount rate for FVLCD. In determining FVLCD, recent market transactions are taken into account, if available. In the absence of such transactions, the discounted cash flow model is used. In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, 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 if there has been a change in the estimates used to determine the recoverable amount. 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 or amortization, if no impairment loss had been recognized. Impairment reversals are recognized in profit or loss.

Financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset (other than a financial asset classified as fair value through profit or loss) is impaired. The criteria used to determine if objective evidence of an impairment loss include:

(i) significant financial difficulty of the obligor;

(ii) delinquencies in interest or principal payments; and

(iii) it becomes probable that the borrower will enter bankruptcy or other financial reorganization.

For equity securities, a significant or prolonged decline in the fair value of the security below its cost is also evidence that the assets are impaired. If such evidence exists, the Company recognizes an impairment loss, as follows:

(i) Financial assets carried at amortized cost: The loss is the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. The carrying amount of the asset is reduced by this amount either directly or indirectly through the use of an allowance account.

(ii) Available for sale financial assets: The impairment loss is the difference between the original cost of the asset and its fair value at the measurement date, less any impairment losses previously recognized in the statement of income. This amount represents the loss in accumulated other comprehensive income or loss that is reclassified to net income. Available for sale financial assets are tested for impairment on an equity by equity basis.

Impairment losses on financial assets carried at amortized cost and available for sale debt instruments are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized. Impairment losses on available for sale equity instruments are not reversed.

g) Share based compensation

The Company has issued options to directors, officers and employees.

In December 2015, the Company changed the accounting for its stock-based compensation awards to assume that options will be equity-settled instead of cash-settled. The change was made to reflect the settlement history of the options and the Company's intent to only settle options in equity in the future. Under the equity settled method, compensation costs attributable to stock options granted to employees, officers or directors are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. The exercise of stock options is recorded as an increase in Common Shares with a corresponding reduction in contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

h) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

Asset retirement obligation

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Asset retirement obligations are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the balance sheet date. The best estimate of the provision is recorded on a discounted basis using a risk-free interest rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as accretion of the asset retirement obligation whereas increases or decreases due to changes in the estimated future cash flows and risk-free rates are adjusted through property, plant and equipment or exploration and evaluation assets. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision.

i) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is when legal title passes to the external party and collectability is reasonably assured. Revenue is measured net of royalties. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

j) Income tax

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax asset will be realized.

The effect of a change in enacted or substantively enacted income tax rates on future income tax assets and liabilities is recognized in profit or loss in the period that the change occurs unless the original entry was recorded to equity.

k) Net profit or loss per share

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated using the weighted average number of shares outstanding, adjusted for the potential number of shares which may have a dilutive impact on net profit. Potentially dilutive shares include stock options. The weighted average number of diluted shares is calculated in accordance with the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase Common Shares at the average market price.

Since the options may be settled in cash or shares at the Company's discretion and therefore there is no obligation to settle in cash, the share units are accounted for as equity-settled share based payment transactions and included in diluted profit per share if the effect is dilutive.

l) Flow-through shares

The Company may issue flow-through shares to fund a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. The difference between the value ascribed to flow-through shares issued and the value that would have been received for Common Shares with no tax attributes is initially recognized as a liability. When the expenditures are incurred, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the renunciation and the difference is recognized as a deferred tax expense.

4. Changes in Accounting Policies and Disclosures

Changes in Accounting Policies for 2016

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2016.

Future Accounting Pronouncements

The following standards and interpretations have not been illustrated as they will only be applied for the first time in future periods. They may result in consequential changes to the accounting policies and other note disclosures. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements.

IFRS 16 *Leases*

On January 13, 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded. IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 *Revenue From Contracts With Customers* has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements.

IFRS 15 *Revenue From Contracts With Customers*

In May 2014, the IASB published IFRS 15 *Revenue From Contracts With Customers* ("IFRS 15") replacing IAS 11 *Construction Contracts*, IAS 18 *Revenue* and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

IFRS 9 *Financial Instruments*

In February 2014, the IASB tentatively decided to require an entity to apply IFRS 9 *Financial Instruments* for annual periods beginning on or after January 1, 2018. The full impact of the standard on the Company's financial statements will not be known until changes are finalized. Early adoption is permitted.

5. Cash and Cash Equivalents

($ thousands)	December 31, 2016	December 31, 2015
Bank balances	$ 7,959	$ -
Short-term bank deposits	316	343
	$ 8,275	$ 343

6. Financial Risk Management and Determination of Fair Values

a) Overview

The Company'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. The Company manages its exposure to these risks by operating in a manner that minimizes this exposure.

b) Fair value of financial instruments

The Company's financial instruments as at December 31, 2016 included cash and cash equivalents, accounts receivable, risk management contracts, deposits, investments, credit facilities and accounts payable and accrued liabilities. As at December 31, 2016, the fair values of the Company's financial assets and liabilities equaled their carrying values due to the short-term maturity, except for the Company's investments and the risk management contracts, which are recorded at fair value.

Disclosures about the inputs to fair value measurements are required, including their classification within a hierarchy that prioritizes the inputs to fair value measurement.

Level 1 Fair Value Measurements

Level 1 fair value measurements are based on unadjusted quoted market prices.

Level 2 Fair Value Measurements

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.

The Company's risk management contracts are considered a level 2 instrument. The Company's financial derivative instruments are carried at fair value as determined by reference to independent monthly forward settlement prices and currency rates.

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

The Company's investments are considered a Level 3 instrument. The fair values are determined using a net asset value approach. Refer to Note 7.

The Company's inputs for the goodwill, property, plant and equipment and exploration and evaluation assets are considered level 3 fair value measurements. Refer to Note 8 and 9.

c) Credit risk

Credit risk represents the potential financial loss to the Company if a customer or counterparty to a financial instrument fails to meet or discharge their obligation to the Company. Credit risk arises principally from the Company's receivables from joint venture partners and oil and gas marketers. The carrying amounts of accounts receivable and cash and cash equivalents represent the maximum credit exposure.

Substantially all of the accounts receivable are with oil and natural gas marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable counterparties and partners.

Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major oil and natural gas marketing companies and the Company has not experienced any credit loss relating to these sales.

Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company mitigates this risk by obtaining pre-approval of significant capital expenditures.

The Company's accounts receivables are aged as follows:

($ thousands)	**December 31, 2016**	December 31, 2015
Current	**$ 2,058**	$ 2,162
31 - 60 days	**27**	221
61 - 90 days	**51**	101
>90 days	**355**	332
Allowance for doubtful accounts	**(152)**	(148)
	$ 2,339	$ 2,668

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. There are no material financial assets that the Company considers past due that are considered impaired.

Cash and cash equivalents include cash bank balances and short-term deposits. The Company manages the credit risk exposure by investing in Canadian banks and credit unions. Management does not expect any counterparty to fail to meet its obligations.

d) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production, develop reserves and to potentially acquire strategic assets. The Company's capital programs are funded principally by cash obtained through its credit facilities, equity issuances and from operating activities. During times of low oil and natural gas prices, a portion of capital programs can generally be deferred, however, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, to the extent possible, the Company will use derivative instruments to manage cash flow in the event of commodity price declines.

The Company's financial obligations relate to trade and other payables, which consist of invoices payable to trade suppliers relating to the office and field operating activities and its capital spending program. The Company processes invoices within a normal payment period and all amounts are due within the next 12 months.

e) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's profit or loss or the value of the financial instruments. The objective of the Company is to mitigate exposure to these risks while maximizing returns to the Company.

<u>Commodity price risk</u>

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Company may enter into oil and natural gas contracts to protect, to the extent possible, its cash flow on future sales. The contracts reduce the volatility in sales revenue by locking in prices with respect to future deliveries of oil and natural gas.

As at December 31, 2016, the Company had the following outstanding commodity risk management contracts in place:

Risk Management Contract	Volumes	Average Price	Term	Fair Value Liability *($ thousands)*
AECO call option sale	3,000 GJ/d	$2.70/GJ	Jan. 1, 2017 - Dec. 31, 2017	764
WTI Nymex call option sale	200 bbls/d	$80/bbl	Jan. 1, 2017 - Dec. 31, 2017	353

The net risk management position is as follows:

($ thousands)	**December 31, 2016**	December 31, 2015
Risk Management Assets		
Current portion	**$ -**	$ 1,032

($ thousands)	**December 31, 2016**	December 31, 2015
Risk Management Liabilities		
Current portion	**$ 1,117**	$ -
Non-current portion	**-**	618

The Company recorded an unrealized loss of $1.53 million for the year ended December 31, 2016 and an unrealized loss of $0.33 million for the same period in 2015. The Company also recorded a realized gain of $1.33 million for the year ended December 31, 2016 and a realized gain of $0.80 million for the same period in 2015.

The value of Questerre's commodity price risk management contracts fluctuate with changes in the underlying market price of the relevant commodity. A summary of the impact to net income (loss) as a result of changes to commodity prices follows:

Risk Management Contract	Sensitivity Range	Increase	Decrease
WTI NYMEX futures sale	$1/bbl increase or decrease to WTI price over $80/bbl	73,000	(73,000)
AECO futures sale	$0.50/GJ increase or decrease to AECO price over $2.70/GJ	547,500	(547,500)

Currency risk

All of Questerre's petroleum and natural gas sales are denominated in Canadian dollars; however, the underlying market prices for these commodities are impacted by the exchange rate between Canada and the United States. The Company also incurs expenditures in its Jordanian subsidiary that are denominated in Jordanian Dinar and United States dollars. As at December 31, 2016, the Company had no forward foreign exchange contracts in place.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. At December 31, 2016, the Company had credit facilities outstanding of $22.89 million (December 31, 2015 $14.54 million).

f) Capital management

The Company believes with its recently completed private placements in the first quarter of 2017 and positive expected funds flow from operations (an additional IFRS measure defined as net cash from operating activities before changes in non-cash working capital and interest paid or received) in the near future that the Company will be able to meet its foreseeable obligations in the normal course of operations. On an ongoing basis the Company reviews its capital expenditures to ensure that funds flow from operations or access to credit facilities are available to fund these capital expenditures. Refer to Note 13.

The volatility of commodity prices has a material impact on Questerre's adjusted funds flow from operations. Questerre attempts to mitigate the effect of lower prices by entering into risk management contracts, shutting in production in unusually low pricing environments, reallocating capital to more profitable areas and reducing capital spending based on results and other market considerations.

The Company considers its capital structure to include shareholders' equity and any outstanding amounts under its credit facilities. The Company will adjust its capital structure to minimize risk and its cost of capital through the issuance of shares, securing additional credit facilities and adjusting its capital spending as required. Questerre monitors its capital structure based on the current and projected funds flow from operations.

($ thousands)		**December 31, 2016**		December 31, 2015
Credit facilities	**$**	**22,888**	$	14,542
Shareholders' equity		**139,660**		127,453

7. Investments

The investments balance comprises the following private company investments:

($ thousands)		**December 31, 2016**		December 31, 2015
Red Leaf	**$**	**490**	$	500
Investment in private company		**-**		132
	$	**490**	$	632

Questerre has an equity interest in Red Leaf, a private Utah based oil shale and technology company. Red Leaf's principal assets are its proprietary EcoShale In-Capsule Technology to recover oil from shale in addition to its oil shale leases in the Utah. If Red Leaf's EcoShale In-Capsule technology is not technically feasible or commercially viable, then the Company's investment in Red Leaf could be further impaired. The following table sets out the changes in investments:

($ thousands)		December 31, 2016		December 31, 2015
Red Leaf	$	490	$	500
Investment in private company		-		132
	$	490	$	632

For the year ended December 31, 2016, the loss on foreign exchange relating to investments was $0.01 million (December 31, 2015: gain $2.79 million), which was recorded in other comprehensive income (loss) net of deferred tax of $0.002 million (December 31, 2015: $0.37 million).

At December 31, 2016, the Company recorded an impairment charge of $0.13 million relating to an investment in a private company of which $0.1 million was recorded in net loss and $0.03 million in other comprehensive income (loss). At December 31, 2015, the Company recorded an impairment charge of $18.18 million for Red Leaf, of which $15.51 million was recorded in net loss and $2.67 million in other comprehensive income (loss). The remaining impairment charge in 2015 related to its investment in a private company.

The determination of fair value requires management to make judgments, estimates and assumptions. These estimates and judgments are reviewed quarterly and have risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

8. Property, Plant and Equipment

Reconciliation of the property, plant and equipment assets:

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Cost or deemed cost:						
Balance, December 31, 2014	$	175,686	$	1,334	$	177,020
Additions		2,116		-		2,116
Transfer from exploration and evaluation assets		26,299		-		26,299
Balance, December 31, 2015		204,101		1,334		205,435
Additions		3,171		-		3,171
Transfer from exploration and evaluation assets		5,740		-		5,740
Balance, December 31, 2016	**$**	**213,012**	**$**	**1,334**	**$**	**214,346**
Accumulated depletion, depreciation and impairment losses:						
Balance, December 31, 2014	$	79,821	$	1,192	$	81,013
Depletion and depreciation		9,676		54		9,730
Disposition		-		-		-
Impairment		27,145		-		27,145
Balance, December 31, 2015		116,642		1,246		117,888
Depletion and depreciation		8,823		38		8,861
Impairment		472		-		472
Balance, December 31, 2016	**$**	**125,937**	**$**	**1,284**	**$**	**127,221**

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Net book value:						
At December 31, 2015	$	87,459	$	88	$	87,547
At December 31, 2016	**$**	**87,075**	**$**	**50**	**$**	**87,125**

During the year ended December 31, 2016, the Company capitalized administrative overhead charges directly related to development activities of $0.06 million. For the year ended December 31, 2015, the Company derecognized $0.03 million in capitalized stock based compensation expense directly related to these activities. Included in the December 31, 2016 depletion calculation are future development costs of $177.86 million (December 31, 2015: $134.74 million). As at December 31, 2016, $2.50 million of assets under construction were included within property, plant and equipment (December 31, 2015: Nil) and not subject to depletion and depreciation.

In 2016, the Company reviewed the carrying amounts of its oil and gas assets for indicators of impairment such as changes in future prices, future costs and reserves. Based on this review, the Company's CGUs of Antler, Midway, Other Alberta and Vulcan were tested for impairment in accordance with the Company's accounting policy. No indicators of impairment were observed for the Company's Montney CGU. The recoverable amount of the CGUs was estimated based on the FVLCD using a discounted cash flow model.

The estimates of FVLCD were determined using a discount rate of 10% and forecasted after-tax cash flows based on proved plus probable reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report.

The future prices used to determine cash flows from crude oil and natural gas reserves are as follows:

	2017	2018	2019	2020	2021	Average Annual % Change Thereafter
WTI (US$/barrel)	55.00	58.70	64.20	69.00	75.80	0.02
AECO ($/MMbtu)	3.40	3.15	3.30	3.60	3.90	0.02

Based on its assessment, the Company recorded an impairment loss of $0.47 million relating to its Vulcan and Other Alberta CGUs. The factor that led to the impairment was a reduction in forecasted commodity prices. The recoverable amounts at December 31, 2016 for these CGUs are as follows:

($ thousands)		Vulcan		Other Alberta
Recoverable amounts	$	-	$	307

For the purpose of impairment testing, the Company assesses goodwill for impairment at the Canada level, which represents the Company's only operating segment. Changes to the assumed discount rate or forward price estimates independently would have the following impact on impairment at the Canada operating segment level:

($ thousands)	One Percent Decrease in the Discount Rate	One Percent Increase in the Discount Rate	Five Percent Increase in the Forward Price Estimates	Five Percent Decrease in the Forward Price Estimates
Impairment charge (recovery) of property, plant and equipment	$ (2)	$ 21	$ (34)	$ 53

9. Exploration and Evaluation Assets

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of technical feasibility and commercial viability. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period.

Reconciliation of the movements in exploration and evaluation assets:

($ thousands)	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**$ 47,917**	$ 81,900
Additions	**11,078**	18,943
Transfers to property, plant and equipment	**(5,740)**	(26,299)
Undeveloped lease expiries	**(17,838)**	(3,130)
Impairment recovery (expense)	**23,498**	(23,497)
Balance, end of year	**$ 58,915**	$ 47,917

During the year ended December 31, 2016, the Company capitalized administrative overhead charges of $1.09 million including $0.18 million for capitalized stock based compensation expense directly related to exploration and evaluation activities. During the year ended December 31, 2015, the Company capitalized administrative overhead charges of $1.38 million and no amount was recognized for capitalized stock based compensation expense directly related to exploration and evaluation activities.

In 2016, the Company reviewed the carrying amount of its exploration and evaluation assets for indicators of impairment. The Quebec CGU was tested for impairment in accordance with the Company's accounting policy in light of the introduction of new hydrocarbon legislation in the province in 2016 and an independent assessment of its natural gas resources in Quebec as of December 31, 2016. The recoverable amount of the Quebec CGU was estimated based on the higher of VIU and FVLCD. The estimate of FVCLD was determined using the before-tax cash flows associated with the best estimate of contingent resources in the development on hold sub-category from the independent Quebec Resource Assessment. The cash flows include a 70% risk factor to reflect the chance of development associated with these resources. The cash flows were subsequently tax-effected. Using a 10% discount rate, the estimated FVLCD of these assets is estimated at $258 million and using a 20% discount rate, the estimate of FVLCD is $109 million.

As a result, the Company has recognized a reversal of the impairment loss of $23.50 million recorded in 2015 associated with these assets. The carrying value of this asset is $28.3 million at December 31, 2016 (2015: $4.27 million). In 2016, the Company incurred an expense of $17.84 million for upcoming undeveloped land expiries at Pasquia Hills and Wapiti (2015: $3.13 million).

10. Deferred Income Taxes

The tax on the Company's net loss before taxes differs from the amount that would arise using the weighted average tax rate applicable to profits or losses of the consolidated entities as follows:

($ thousands)		December 31, 2016		December 31, 2015
Net income (loss) before taxes	$	614	$	(71,413)
Combined federal and provincial tax rate		27.00%		26.13%
Computed "expected" deferred tax expense (recovery)		166		(18,660)
Increase (decrease) in deferred taxes resulting from:				
Non-deductible differences		(50)		2,035
Deferred tax asset not recognized in year		277		20,721
Rate adjustments		52		(1,975)
Other		-		-
Deferred tax expense	$	445	$	2,121

In the fourth quarter of 2016, the Company evaluated the recoverability of its deferred tax assets using forecasted before-tax cash flows based on proved reserves, with escalating prices and future development costs obtained from an independent reserve evaluation report and a deduction for estimated general and administrative costs associated with these proved reserves. The statutory tax rate was 27% in 2016 and 26.13% in 2015.

The movement of the deferred tax asset is as follows:

($ thousands)		December 31, 2016		December 31, 2015
Balance, beginning of year	$	18,827	$	20,827
Tax recorded to statement of net profit or loss		(445)		(2,121)
Tax on share issue costs		182		-
Tax charge relating to flow through shares		(919)		-
Tax charge relating to components of other comprehensive income or loss		-		121
Balance, end of year	$	17,645	$	18,827

The movement in deferred tax assets during the year, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

($ thousands)	Petroleum and natural gas properties	Asset retirement obligation	Share issue costs	Non-capital losses
Deferred tax asset:				
Balance, December 31, 2014	$ 897	$ 2,089	$ 348	$ 19,292
Credited (charged) to				
net profit or loss	14,627	274	(103)	(16,920)
Balance, December 31, 2015	15,524	2,363	245	2,372
Credited (charged) to				
net profit or loss	(8,974)	(7)	26	7,612
Balance, December 31, 2016	**$ 6,550**	**$ 2,356**	**$ 271**	**$ 9,984**

The amount and timing of reversals of temporary differences will be dependent upon, among other things, the Company's future operating results, and acquisitions and dispositions of assets and liabilities.

Deferred income tax assets are recognized for tax loss carry-forwards to the extent that the realization of the related tax benefit through future taxable profits is probable. It is expected that future cash flows, generated from its existing proved reserves, will be sufficient to provide future taxable profits to utilize the deferred tax assets.

Non-capital loss carry-forwards at December 31, 2016 expire from 2026 to 2035.

The movement in deferred tax liabilities during the year, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

($ thousands)	Investments	Other
Deferred tax liability:		
Balance, December 31, 2014	$ 1,629	$ 169
Charged (credited) to net profit or loss	79	(79)
Charged to other comprehensive income or loss	(121)	-
Balance, December 31, 2015	1,587	90
Charged (credited) to net profit or loss	(2)	232
Charged to other comprehensive income or loss	28	-
Balance, December 31, 2016	**$ 1,613**	**$ 322**

Deferred tax assets have not been recognized in respect of the following items:

($ thousands)	December 31, 2016	December 31, 2015
Petroleum and natural gas properties	$ 219	$ 219
Investments	40,738	40,595
Non-capital losses	104,470	67,463
Capital losses	36,488	36,488
	$ 181,915	$ 144,765

The Company does not expect to recover or settle its deferred tax assets and liabilities within the next twelve month period.

11. Share Based Compensation

The Company has a stock option program that provides for the issuance of options to its directors, officers and employees at or above grant date market prices. The options granted under the plan generally vest evenly over a three-year period starting at the grant date or one year from the grant date. The grants generally expire five years from the grant date or five years from the commencement of vesting.

Under the Company's option plan, a put right is included that allows the optionee to settle options with cash or equity. The Company does not intend to cash settle these options in future periods. The Company has the option to decline a put right exercise at any time. Under the put right, the optionee will receive the net cash proceeds that is the excess of the closing price at the day of the put notice over the exercise price. Once the options are cash settled, the options are cancelled.

The number and weighted average exercise prices of stock options are as follows:

	Options Outstanding			Options Exercisable		
	Number of Options *(thousands)*	Weighted Average Years to Expiry	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Years to Expiry	Weighted Average Exercise Price
$0.175 - $0.30	9,605	3.77	$0.24	2,909	3.59	$0.26
$0.31 - $0.70	1,891	3.10	0.34	526	2.63	0.42
$0.71 - $1.00	3,060	1.48	0.88	2,358	1.48	0.88
$1.01 - $1.40	300	2.48	1.36	146	2.47	1.37
	14,856	3.19	$0.41	5,939	2.64	$0.55

The following table summarizes information about stock options outstanding and exercisable at December 31, 2016:

	December 31, 2016		December 31, 2015	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	19,982	$0.72	17,792	$1.96
Granted	4,100	0.18	10,532	0.29
Forfeited	(4,289)	0.47	(2,819)	1.10
Expired	(3,260)	1.85	(5,523)	3.68
Exercised	(1,677)	0.60	-	-
Outstanding, end of period	14,856	$0.41	19,982	$0.72
Exercisable, end of period	5,939	$0.55	6,808	$0.97

The fair value of the liability was calculated using the Black-Scholes valuation model. The following weighted average assumptions were used in the model for options granted in 2016:

	December 31, 2016	December 31, 2015
Weighted average fair value per award ($)	0.10	0.14
Volatility (%)	67.15	62.88
Forfeiture rate (%)	13.42	9.60
Expected life (years)	5.00	4.41
Risk free interest rate (%)	0.53	0.68

This forfeiture rate estimate is adjusted to the actual forfeiture rate. Expected volatility and expected life is based on historical information.

In December 2015, the Company changed the accounting for its stock-based compensation awards to assume that options will be equity-settled instead of cash-settled. The change was made to reflect the settlement history of the options. As a result of the change, the Company transferred $0.27 million from Share based Compensation Liability to Contributed Surplus.

12. Asset Retirement Obligation

The Company's asset retirement and abandonment obligations result from its ownership interest in oil and natural gas assets. The total asset retirement obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of the asset retirement obligation to be $8.73 million as at December 31, 2016 (December 31, 2015: $8.75 million) based on an undiscounted total future liability of $11.37 million (December 31, 2015: $11.31 million). These payments are expected to be made over the next 40 years. The average discount factor, being the risk-free rate related to the liabilities, is 1.56% (December 31, 2015: 1.35%). An inflation rate of

2.2% (December 31, 2015: 2.2%) over the varying lives of the assets is used to calculate the present value of the asset retirement obligation.

The following table provides a reconciliation of the Company's total asset retirement obligation:

($ thousands)		**December 31, 2016**		December 31, 2015
Balance, beginning of year	**$**	**8,752**	$	8,133
Liabilities disposed		**-**		(68)
Liabilities incurred		**161**		296
Liabilities settled		**(18)**		(60)
Revisions due to change in discount and inflation rates		**(311)**		(379)
Revisions due to change in estimates		**-**		715
Accretion		**142**		115
Balance, end of year	**$**	**8,726**	$	8,752

13. Credit Facility

As at December 31, 2016, the credit facilities includes a revolving operating demand facility of $24.9 million ("Credit Facility A"), a non-revolving acquisition and development facility of $5.0 million ("Credit Facility B") and a corporate credit card of $0.1 million ("Credit Facility C"). Credit Facility A can be used for general corporate purposes, ongoing operations, capital expenditures within Canada, and acquisition of petroleum and natural gas assets within Canada. Credit Facility B can only be used for the acquisitions of producing reserves and/or development of existing proved non-producing/undeveloped reserves.

Any borrowing under the facilities, with the exception of letters of credit, bears interest at the bank's prime interest rate and an applicable basis point margin based on the ratio of debt to cash flow measured quarterly. The bank's prime rate currently is 2.70% per annum. The facilities are secured by a debenture with a first floating charge over all assets of the Company and a general assignment of books debts. Under the terms of the credit facility, the Company has provided a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at December 31, 2016 was 2.47 and the covenant was met. At December 31, $22.89 million (December 31, 2015: $14.52 million) was drawn on Credit Facility A.

The credit facilities are a demand facility and can be reduced, amended or eliminated by the lender for reasons beyond the Company's control. Should the credit facilities, in fact, be reduced or eliminated, the Company would need to seek alternative credit facilities or consider the issuance of equity to enhance its liquidity.

In February 2017, Credit Facility A was renewed at $22.9 million, Credit Facility B was terminated and Credit Facility C remains at $0.1 million.

14. Share Capital

The Company is authorized to issue an unlimited number of Common Shares. The Company is also authorized to issue an unlimited number of Class "B" common voting shares and an unlimited number of preferred shares, issuable in one or more series. At December 31, 2015, there were no Class "B" common voting shares or preferred shares outstanding.

a) Issued and outstanding – Common Shares

	Number (thousands)		Amount ($ thousands)
Balance, December 31, 2014	264,932		347,345
Balance, December 31, 2015	264,932		347,345
Private Placements	41,592		11,279
Options exercised	1,677		1,006
Warrants exercised	73		15
Share issue costs (net of tax effect)	-		(494)
Balance, December 31, 2016	**308,274**	**$**	**359,151**

b) Per share amounts

Basic net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2016**		December 31, 2015
Net loss ($ thousands)	**$**	**169**	$	(73,534)
Weighted average number of Common Shares outstanding (basic)		**278,662**		264,932
Basic net loss per share	**$**	**0.00**	$	(0.28)

Diluted net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2016**		December 31, 2015
Net loss ($ thousands)	**$**	**169**	$	(73,534)
Weighted average number of Common Shares outstanding (basic)		**278,662**		264,932
Effect of outstanding options		**1,748**		-
Weighted average number of Common Shares outstanding (diluted)		**280,410**		264,932
Diluted net loss per share	**$**	**0.00**	$	(0.28)

Under the current stock option plan, options can be exchanged for Common Shares of the Company, or for cash at the Company's discretion. They are considered potentially dilutive and are included in the calculation of diluted net loss per share for the period. The average market value of the Common Shares for purposes of calculating the dilutive effect of options was based on quoted market prices for the period that the options were outstanding. At December 31, 2016, 14.58 million options (December 31, 2015: nil) were excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

15. Petroleum and Natural Gas Sales

($ thousands)		**December 31, 2016**		December 31, 2015
Oil and liquids	**$**	**13,919**	$	17,332
Natural gas		**3,201**		4,683
	$	**17,120**	$	22,015

16. Employee Salaries and Benefits

($ thousands)		**December 31, 2016**		December 31, 2015
Salaries, bonuses and other short-term benefits	**$**	**1,625**	$	2,096
Share based compensation (recovery)		**303**		(83)
	$	**1,928**	$	2,013

17. Key Management Compensation

Key management includes directors and officers. The compensation paid or payable to key management is as follows:

($ thousands)		**December 31, 2016**		December 31, 2015
Salaries, bonuses, director fees and other short-term benefits	**$**	**1,287**	$	1,916
Share based compensation (recovery)		**271**		(36)
	$	**1,558**	$	1,880

The Company has entered into written executive employment agreements with each of the officers of the Company. Each of these written agreements provides that in the event of a change of control of the Company, each of the officers is entitled to: (i) one month of then applicable base salary per year of service with the Company; and (ii) the vesting of all options to purchase Common Shares. In the event of a change in control, the severance payable to key management would have been $1.06 million at December 31, 2016.

18. Supplemental Cash Flow Information

Changes in non-cash working capital are detailed below:

($ thousands)		December 31, 2016		December 31, 2015
Accounts receivable	$	329	$	(61)
Deposits and prepaid expenses		(43)		207
Accounts payable and accrued liabilities		(5,157)		(14,379)
Change in non-cash working capital	$	(4,871)	$	(14,233)
Related to:				
Operating activities	$	586	$	(596)
Investing activities		(5,457)		(13,637)
	$	(4,871)	$	(14,233)

19. Commitments

A summary of the Company's net commitments at December 31, 2016 follows:

($ thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation, Marketing and Processing	$ 4,728	$ 4,728	$ 3,990	$ 3,990	$ 3,990	$ 19,952	$ 41,378
Office Leases	112	99	99	90	-	-	400
	$ 4,840	$ 4,827	$ 4,089	$ 4,080	$ 3,990	$ 19,952	$ 41,779

In the fall of 2013, the Company entered into a series of take or pay agreements for the processing, transportation, fractionating and marketing of 20 MMcf/d of raw gas and associated liquids production in the Kakwa-Resthaven area (the "Infrastructure Contracts"). In December 2014, the Company assigned a 57.5% interest in the Infrastructure Contracts on a permanent basis to third parties. Concurrently, the Company also assigned an 18.75% interest in the Infrastructure Contracts on a temporary basis to a third party until December 2016.

20. Summary Judgement

In November 2016, the Company received a favorable ruling with respect to its appeal of a summary judgement issued in December 2015. In March 2017, Questerre was refunded $5.9 million as a result of this appeal. The joint venture partner has appealed this ruling and a date for this hearing is to be determined. The refund will be recorded in the Company's current assets with an offsetting liability in respect of the potential exposure for the these costs primarily relating to drilling two wells in Quebec in 2010. A trial is currently scheduled for late 2018 in respect of the Company's obligations primarily related to these two wells.

21. Related Party Transactions

Other than indicated below, the Company did not engage in any related party transactions during the quarter ended December 31, 2016.

Certain directors and officers of the Company participated in the Flow-Through Placement, which constituted a “related party transaction” within the meaning of Multilateral Instrument 61-101 – *Protection of Minority Security Holders in Special Transactions* (“MI 61-101”). Questerre relied upon exemptions from the formal valuation and minority approval requirements of MI 61-101 based on a determination that the fair market value of the placement, insofar as it involved related parties, did not exceed 25% of the market capitalization of the Company.

22. Subsequent Events

In February 2017, the Company concluded a private placement of 30.8 million Common Shares at a price of $0.79 per Common Share for gross proceeds of approximately $24 million.

In February 2017, Credit Facility A was renewed at $22.9 million, Credit Facility B was terminated and Credit Facility C remains at $0.1 million.

In March 2017, in connection with the private placement completed by the Company in November 2016, the Company completed a subsequent private placement of 1.4 million Common Shares at a price of $0.49 per Common Share for gross proceeds of $0.7 million.

Corporate Information

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Alain Sans Cartier

Earl Hickok

Dennis Sykora

Bjorn Inge Tonnessen

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