2017

ANNUAL REPORT

QUESTERRE ENERGY CORPORATION

2017

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

2017 was a turning point for Questerre. We were pleased to make progress on all our projects during the year.

We participated in seven gross wells on our Kakwa joint venture acreage. Exit production from the area doubled in 2017 and, with similar investment, growth should continue for the next few years. Coupled with a light oil acquisition in Saskatchewan, we saw a material improvement in our proved and probable reserves. We also brought in a partner to develop our operated acreage at Kakwa, substantially reducing the capital required to create additional value.

In Quebec, we stayed focused on the regulations and social acceptability. We were pleased to see the government publish the draft oil and gas regulations last fall. We are looking forward to the final regulations this spring. Our clean gas pilot is gaining support among industry and stakeholders. Along with our local revenue sharing initiative, this will be vital to secure the acceptability we need.

We made headway on the engineering for our multi-billion barrel oil shale resource in Jordan. The last three of nine independent studies were completed. We have engaged an engineering firm to review and integrate this work. We also made a strategic investment in Red Leaf as their EcoShale process could be essential to developing this project at current oil prices.

We strengthened our balance sheet through equity placements for gross proceeds of approximately $56 million.

Highlights

- Kakwa development resumes with drilling of 7 (1.60 net) wells in 2017
- Quebec Government publishes draft hydrocarbon and environmental regulations for future development
- Internal feasibility study completed and supports concession application for Jordan oil shale project
- Total proved and probable reserves increased 20% to 27.11 MMboe with a before income tax NPV-10% of $174.69 million

Kakwa-Resthaven, Alberta

Our 2017 wells benefitted from the improvements made in prior years.

These include drilling longer laterals and using more sand per metre in the fracs. This contributed to an increase in our type curve last year to 1.01 MMboe on a proved and probable basis. We are incrementally drilling longer wells and using higher sand tonnage where possible. Our most recent well pairs are targeting adjacent intervals in the Montney to see if inter-well spacing can be reduced to less than 200m. This could increase the number of wells on our acreage.

Based on lateral lengths of approximately 1.5 miles and spacing of 200m between wells, there are over 50 (12.5 net) wells to be drilled on our joint venture block. Though we see some cost inflation in coming years, mainly for completions, we expect capital and operating costs will benefit from our $11 million investment in infrastructure over the last two years. These included the first phase of a central water storage facility, gas lift facilities and a regenerative amine system. We anticipate a further investment of approximately $15 million over the next two years that will include the next phase of the central water storage facility and a staged expansion of the central processing facility to 60 MMcf/d plus associated liquids.

We plan to use our share of these expanded facilities to process any volumes from our adjacent seven section block where we have recently brought in a partner. We are looking forward to the first results from this block later this year. Based on similar spacing and well length, success here could more than double the number of Questerre's net locations at Kakwa.

St. Lawrence Lowlands, Quebec

Final regulations and local acceptability are the remaining two hurdles to resuming drilling in Quebec.

The draft regulations introduced last fall appear workable but could be improved to be more efficient and competitive. We have provided our feedback to the ministries of energy and the environment on both the oil and gas and environmental regulations. We are looking forward to the final oil and gas regulations later this spring and the final environmental regulations this fall. Most importantly, the regulations allow us to drill and complete wells in Quebec subject to securing social acceptability.

Just as our step by step approach with the government was successful in introducing the new law, we think our clean gas pilot and local revenue sharing could do the same for social acceptability. We expect this will meet with opposition from some municipalities. However, in municipalities that are open to development, we are hopeful it can be done over the next twelve months.

We are designing our clean gas pilot to reduce emissions, fresh water usage and noise. This would use Quebec's abundant hydroelectricity to power compressors and eventually drilling rigs. It is similar to the North Sea where production platforms are now being electrified. We plan to store and recycle water used for completions, similar to our operations at Kakwa. We are also discussing with local communities how they could share financially in local development.

Oil Shale Mining

Our project in Jordan is at an earlier stage but still similar in scale to Quebec.

Jordan has well established regulations for oil shale development and is a premium market for oil because it imports over 100,000 bbl/d to meet its energy needs. The country is focused on the development of its natural resources, particularly its oil shale deposits, which rank among the largest in the world. The challenge is how to develop our multi-billion barrel oil shale deposit in the current price environment.

Our oil shale in Jordan is unique. It is primarily a marlstone or chalk with approximately 25% water by weight and relatively high in sulphur. Efficiently heating the shale and capturing the large volumes of water for future use in the process is critical. We are evaluating three different retorting processes with this goal in mind.

We acquired additional common shares and now hold approximately 30% of the common share capital of Red Leaf. We continue to work with them to further optimize their process for our shale.

Our goal for 2018 is to have a third party engineering firm validate and integrate our internal assessment and cost estimates based on the nine studies completed to date. We are targeting an initial project size of 50,000 bbl/d to benefit from the economies of scale, particularly those related to upgrading the produced oil to diesel and gasoline. Concurrently, we plan to begin negotiations with the Jordanian government for a concession agreement.

Operational & Financial

While our exit production from Kakwa doubled over the year to 1,358 boe/d and contributed to corporate volumes of 1,714 boe/d in the fourth quarter, our average daily production over the year remained relatively unchanged at 1,373 boe/d from the prior year. Higher oil prices in 2017 were offset by increased operating costs, particularly at Kakwa and Antler, resulting in adjusted funds flow from operations of $6.78 million.

In addition to a $27.75 million investment primarily in our producing assets at Kakwa and Antler, we also made a $10.33 million investment to increase our equity interest in Red Leaf.

Outlook

We will make a similar investment in Kakwa this year based on well performance and current prices. Subject to the operator's plans, this should again grow our production and reserves next year. Success on our Kakwa North acreage could add further incremental reserves.

Despite the outlook for natural gas prices, we are still bullish on our Quebec Utica gas discovery because the analogous Ohio Utica is exceeding expectations and the province remains a premium natural gas market. We have been designing our clean gas pilot to address stakeholder concerns and it fully aligns with the province's goals of reducing energy imports and emissions.

While the outlook for oil prices is improving, we are focused on making our project in Jordan economic at current prices. We expect the engineering work completed in 2018 will give us more refined estimates of the costs to develop this multi-billion barrel oil shale resource.

Michael Binnion, President and Chief Executive Officer

Principal Areas of Operation

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 18,560 (10,880 net) acres in the area, including a 100% working interest in 4,480 acres ("Kakwa North") and a 100% interest in 3,840 acres ("Kakwa South").

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.

Questerre invested $22.39 million at Kakwa (2016: $11.91 million) with daily production averaging 1,123 boe/d in 2017 (2016: 1,036 boe/d). Total proved and probable reserves at December 31, 2017 were estimated at 16.09 MMboe (2016: 14.21 MMboe) with a NPV-10% of $121.59 million (2016: $118.92 million).

During the year, activity focused on the drilling of 7 (1.60 net) wells and the expansion of field infrastructure on its joint venture acreage. The majority of the wells were completed and tied-in during the year. Questerre holds an average working interest of 23% in these wells.

The wells drilled during the year include the 100/09-29-63-5W6M (the "100/09-29 Well"), 102/09-29-63-5W6M (the "102/09-29 Well"), 100/01-20-63-6W6M Well ("01-20 Well") and the 102/06-18-63-5W6M Well ("06-18 Well"). Production over the first thirty days from the Montney for the 100/09-29 Well, 102/09-29 Well and the 100/01-20 Well averaged 2.7 MMcf/d and 827 bbls/d of condensate and other liquids (1,277 boe/d). Although the initial results from these wells are encouraging, they are not necessarily indicative of long-term performance or ultimate recovery.

An investment of $7.74 million (2016: $3.26 million) was made in field infrastructure to support future growth. These included a regenerative amine sweetening system, central water processing facility and gas lift facilities. The amine system has largely eliminated the operating costs associated with chemical sweetening. The first phase of the central water facility was completed in the fourth quarter and will temporarily store produced water for future completion operations. The gas lift facilities have improved uptime and are assisting with the lifting of produced liquids. Additional gas lift facilities are planned for 2018.

The Company is also participating in the planned expansion of the central processing facility from its current operating capacity of approximately 23 MMcf/d to 45 MMcf/d plus associated liquids. The plans contemplate a future expansion to 60 MMcf/d. Based on commodity prices and continued results Questerre plans to participate in the drilling of up to six (1.5 net) additional wells at its joint venture acreage during 2018. The majority of these wells should be drilled in the second half of the year to coincide with the scheduled in-service date for the facility expansion.

To evaluate its operated acreage in the area, the Company entered into a farm-out agreement with an experienced Montney operator in the first quarter of 2018. Pursuant to the agreement, the partner has the right to drill, complete, equip and tie-in two horizontal wells targeting the Montney formation to earn a 50% interest in certain acreage held by Questerre at Kakwa North. The partner has the option to drill, complete, equip and tie-in additional wells to earn a similar interest in other acreage held by Questerre at Kakwa North and Kakwa South. Questerre will hold a royalty interest in these initial wells and certain subsequent wells subject to standard payout provisions. The Company expects the first well to spud during the second quarter of 2018.

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 currently holds 12,690 net acres in the Antler area.

Activities at Antler focused on the optimization of existing production and the pilot waterflood to increase recovery of the oil in place. The Company also consolidated its interest in the area through an acquisition completed in the fourth quarter of 2017.

Including the acquisition for gross consideration of $7.25 million before customary adjustments, Questerre invested $8.79 million at Antler (2016: $0.54 million) with daily production averaging 179 bbl/d (2016: 209 bbl/d). Total proved and probable reserves at December 31, 2017 were estimated at 2.02 MMbbls (2016: 1.16 MMbbls) with a NPV-10% of $48.72 million (2016: $31.25 million).

The acquisition consisted of approximately 180 bbls/d of light oil production. Acquired assets include 3D seismic data over the producing acreage. The proved and probable reserves associated with these assets were assessed at 0.93 MMbbls at December 31, 2017.

In 2018, Questerre plans to continue work on production optimization and the pilot waterflood.

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.

In March 2017, the Quebec Government passed into law 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*. One of the key features of Bill 102 is to establish a simplified and modulated authorization process based on the environmental risks associated with a project. Bill 102 also includes changes to various provisions of Quebec's *Environmental Quality Act* governing, in particular, contaminated lands, residual materials and hazardous materials. The majority of the changes introduced by Bill 102 entered into force on March 23, 2018. In February 2018, the Quebec Government published several draft regulations in the Gazette officielle du Québec to implement some of the changes introduced by Bill 102. The majority of such regulations will come into force by the end of 2018.

In September 2017, the Ministry of Natural Resources published the proposed regulations to govern oil and gas activities in the province. The draft regulations are required for the implementation of the *Petroleum Resources Act.*

The purpose of the *Petroleum Resources Act* is: (i) to replace the current oil & gas statutory framework set by the *Quebec Mining Act*; and (ii) to govern the development of petroleum resources while ensuring the safety of persons and property, environmental protection and optimal recovery of the resource, in compliance with the greenhouse gas emission reduction targets set by the Quebec Government. The *Petroleum Resources Act* will come into force on a date to be set by the Quebec Government, which is expected to be on or about the same time as the adoption of the final version of the draft regulations.

In December 2017, the Quebec Government published the "Draft regulation respecting the environmental impact assessment and review procedure of certain projects". Following Bill 102, the new Regulation is consistent with the *Sustainable Development Act* and proposes further changes to the current environmental impact assessment and review regime of the *Environment Quality Act*. Such changes include increased public participation in the process, greater mandated disclosure on the part of project proponents, a longer list of projects subject to the environmental assessment process, and various revised thresholds for those projects' compliance with the Act. This draft regulation entered into force on March 23, 2018.

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

In early 2018, the Company engaged GLJ Petroleum Consultants Ltd. ("GLJ") to update the resource assessment of its Utica acreage in Quebec effective December 31, 2017 with a report date of March 16, 2018 (the "Quebec Resource Assessment"). 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 Quebec Resource Assessment assesses the Utica shale gas potential within the Company's 735,910 gross acres in the St. Lawrence Lowlands of Quebec. The best estimate by GLJ of risked Prospective Resources net to Questerre is 0.94 trillion cubic feet ("Tcf") (157 million barrels of oil equivalent ("boe")). Additionally, the Quebec Resource Assessment details the best estimate of risked Contingent Resources net to Questerre is 313 Bcf (52 million boe). The net present value of the risked Contingent Resources, including the development on hold and development unclarified sub categories, discounted at 10% before tax is estimated at $409 million.

The updated Quebec Resource Assessment assigned Contingent Resources for approximately 16% of Questerre's acreage based on the results from several vertical and horizontal wells on the Company's acreage that have all encountered pay in the Utica as reported by the Company in 2008 to 2010. 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. Those areas classified as development on hold 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 no certainty that any portion of the Contingent Resources will be economic to develop. Though pilot horizontal development plans have been proposed, the project evaluation scenario for the Contingent Resources is not sufficiently defined to make an investment decision to proceed to development.

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.

For more information, please refer to the Company's 2017 Annual Information Form ("AIF") and press release dated March 12, 2018 available on the Company's website at www.questerre.com and on SEDAR at www.sedar.com.

Oil Shale Mining

Questerre's oil shale assets include its project in the Kingdom of Jordan ("Jordan") and its investment in Red Leaf Resources Inc. ("Red Leaf"). Red Leaf is a private Utah based company whose principal assets include the EcoShale process to produce oil and shale and oil shale leases in the state of Utah. Questerre currently owns approximately 30% of the common share capital of Red Leaf.

The Company acquired the Jordanian 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

“MEMR”). The MOU covered an area of over 380 km^2 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 extended to May 22, 2018. Upon the completion of the MOU and the submission of the required documentation to the MEMR, the Company anticipates it will enter into negotiations with the MEMR for a concession agreement. The Company will continue to hold an exclusive right to the acreage under the MOU during the term of these negotiations. In 2017, the Company high graded its acreage and reduced the area under the MOU to 265 km^2.

Following an independent resource assessment prepared by Millcreek Mining Group (“Millcreek”) in accordance with NI 51-101 and the COGE Handbook effective October 1, 2016, the Company’s primary objective for 2017 was to evaluate the feasibility of commercial development. For more information on the resources assessment, please refer to the Company’s 2016 AIF dated March 24, 2017 and press release dated October 27, 2016 available on the Company’s website at www.questerre.com and www.sedar.com.

The economic feasibility work involves assessing multiple retorting processes specifically for the Jordanian oil shale. This includes two processes that have been proven at commercial scale. Also under evaluation is the EcoShale process developed by Red Leaf. With Questerre, Red Leaf has been redesigning the EcoShale process to focus on reusable capsules. Red Leaf estimates that using large steel vessels similar to those used in coker facilities in refineries instead of the original single use earthen capsule could materially reduce costs.

In addition to assessing the retorting component of production, Questerre commissioned engineering studies to evaluate the three other components - mining and preparation of the ore, infrastructure, including power and other utilities, and upgrading of the produced oil including a marketing study.

Questerre recently completed an internal review of the retorting processes and the engineering studies. Based on the unique characteristics of the Jordanian shale, the Company believes the re-designed EcoShale process could be the most efficient. Early in 2018, the Company engaged a third party engineering firm to integrate all the studies and validate its work. Questerre anticipates this report will be completed in the third quarter of 2018.

During the year, Questerre acquired additional Red Leaf common shares for US$7.52 million. The Company currently holds 132,293 common shares, representing approximately 30% of the common share capital of Red Leaf. Questerre also acquired 288 Series A Preferred Shares, representing less than 0.5% of the issued and outstanding preferred share capital of Red Leaf, for US$0.16 million. For more information, see Note 7 to the Financial Statements.

In addition to its EcoShale process and its oil shale leases in Utah, Red Leaf holds US$104 million in cash and no debt as of December 31, 2017. In addition to common shares, Red Leaf’s equity capital includes convertible preferred shares with dividends accruing at 8% per annum compounded annually. As at December 31, 2017, the preferred shares are entitled to a priority amount of US$83.5 million on the occurrence of a defined liquidation event, including certain reorganizations, takeovers, the sale of all or substantially all the assets of the company and shareholder distributions.

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 and promote the use of technology to improve efficiencies and reduce emissions from our operations.

This Management's Discussion and Analysis ("MD&A") was prepared as of March 29, 2018 and 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, 2017 and 2016. Additional information relating to Questerre, including Questerre's Annual Information Form for the year ended December 31, 2017 ("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;
- the timing of the development of the Company's resources in Quebec;
- liquidity and capital resources;
- the assessment and report of the retorting processes and engineering studies of the Company's oil shale project in Jordan;
- the Company's plans to enter into negotiations for a concession agreement in Jordan;

- 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;
- the efficiency of the re-designed EcoShale process and cost reductions associated therewith;
- ability of the Company to meet its foreseeable obligations;
- expectations regarding the Company's liquidity increasing over time;
- capital expenditures and the funding thereof;
- Questerre's reserves and resources;
- impacts of capital expenditures on the Company's reserves and resources;
- the benefits of the 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 AIF, dated March 29, 2018, 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;

- the passage of applicable hydrocarbon and environmental legislation and regulations and local acceptability;
- 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)		2017		2016
Net cash from operating activities	$	14,661	$	6,719
Interest paid		615		912
Change in non-cash working capital		(8,495)		(586)
Adjusted funds flow from operations	$	6,781	$	7,045

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 risk management contracts.

Select Annual Information

As at/for the years ended December 31,	2017	2016	2015
Financial ($ thousands, except as noted)			
Petroleum and Natural Gas Sales	**21,361**	17,120	22,015
Adjusted Funds Flow from Operations	**6,781**	7,045	9,778
Basic and Diluted ($/share)	**0.02**	0.03	0.04
Net Income (loss)	**(24,821)**	169	(73,534)
Basic and Diluted ($/share)	**(0.07)**	-	(0.28)
Capital Expenditures, net of			
Acquisitions and Dispositions	**27,746**	14,218	20,524
Working Capital Surplus (Deficit)	**9,648**	(17,019)	(21,478)
Total Non-Current Financial Liabilities	**15,952**	8,726	9,370
Total Assets	**217,214**	177,761	161,894
Shareholders' Equity	**170,738**	139,660	127,453
Common Shares Outstanding (thousands)	**385,331**	308,274	264,932
Weighted average - basic (thousands)	**350,055**	278,662	264,932
Weighted average - diluted (thousands)	**350,055**	280,410	264,932
Operations (units as noted)			
Average Production			
Crude Oil and Natural Gas Liquids (bbls/d)	**821**	801	913
Natural Gas (Mcf/d)	**3,350**	3,436	4,012
Total (boe/d)	**1,379**	1,373	1,582
Average Sales Price			
Crude Oil and Natural Gas Liquids ($/bbl)	**61.28**	47.51	51.75
Natural Gas ($/Mcf)	**2.42**	2.55	3.26
Total ($/boe)	**42.44**	34.06	38.13
Netback ($/boe)			
Petroleum and Natural Gas Revenue	**42.44**	34.06	38.13
Royalties Expense	**(2.17)**	(1.86)	(2.16)
Percentage	**5%**	5%	6%
Operating Expense	**(19.93)**	(15.23)	(13.97)
Operating Netback	**20.34**	16.98	22.00
General and Administrative Expense	**(6.24)**	(5.49)	(6.14)
Cash Netback	**14.11**	11.48	15.86
Wells Drilled			
Gross	**7.00**	3.00	1.00
Net	**1.60**	0.75	0.25

Highlights

- Kakwa development resumes with drilling of 7 (1.60 net) wells in 2017
- Quebec Government publishes draft hydrocarbon and environmental regulations for future development
- Internal feasibility study completed and supports concession application for Jordan oil shale project
- Total proved and probable reserves increased 20% to 27.11 MMboe with a before income tax NPV-10% of $174.69 million

2017 Activities

Western Canada

Kakwa-Resthaven, Alberta

Consistent with prior years, Kakwa accounted for the vast majority of the Company's capital spending and production in 2017. Development targeted the condensate-rich Montney formation.

Questerre invested $22.39 million at Kakwa (2016: $11.91 million) with daily production averaging 1,123 boe/d in 2017 (2016: 1,036 boe/d). Total proved and probable reserves at December 31, 2017 were estimated at 16.09 MMboe (2016: 14.21 MMboe) with a before income tax NPV-10% of $121.59 million (2016: $118.92 million). The Company currently holds 18,560 (10,880 net) acres, including a 100% working interest in 8,320 net acres.

During the year, activity focused on the drilling of 7 (1.60 net) wells and the expansion of field infrastructure on its joint venture acreage. The majority of the wells were completed and tied-in during the year. Questerre holds an average working interest of 23% in these wells.

The wells drilled during the year include the 100/09-29-63-5W6M (the "100/09-29 Well"), 102/09-29-63-5W6M (the "102/09-29 Well"), 100/01-20-63-6W6M Well ("01-20 Well") and the 102/06-18-63-5W6M Well ("06-18 Well"). Production over the first thirty days from the Montney for the 100/09-29 Well, 102/09-29 Well and the 100/01-20 Well averaged 2.7 MMcf/d and 827 bbls/d of condensate and other liquids (1,277 boe/d). Although the initial results from these wells are encouraging, they are not necessarily indicative of long-term performance or ultimate recovery.

An investment of $7.74 million (2016: $3.26 million) was made in field infrastructure to support future growth. These included a regenerative amine sweetening system, central water processing facility and gas lift facilities. The amine system has largely eliminated the operating costs associated with chemical sweetening. The first phase of the central water facility was completed in the fourth quarter and will temporarily store produced water for future completion operations. The gas lift facilities have improved uptime and are assisting with the lifting of produced liquids. Additional gas lift facilities are planned for 2018.

The Company is also participating in the planned expansion of the central processing facility from its current operating capacity of approximately 23 MMcf/d to 45 MMcf/d plus associated liquids. The plans contemplate a future expansion to 60 MMcf/d. Based on commodity prices and continued results Questerre plans to participate in the drilling of up to six (1.5 net) additional wells at its joint venture acreage during the year. The majority of these wells should be drilled in the second half of the year to coincide with the scheduled in-service date for the facility expansion.

To evaluate its operated acreage in the area, the Company entered into a farm-out agreement with an experienced Montney operator in the first quarter of 2018. Pursuant to the agreement, the partner has the right to drill, complete, equip and tie-in two horizontal wells targeting the Montney formation to earn a 50% interest in certain Kakwa operated acreage held by Questerre. The partner has the option to drill, complete, equip and tie-in additional wells to earn a similar interest in other Kakwa operated acreage held by Questerre. Questerre will hold a royalty interest in these initial wells and certain subsequent wells subject to standard payout provisions. The Company expects the first well to spud during the second quarter of 2018.

Antler, Saskatchewan

Activities at Antler focused on the optimization of existing production and the pilot waterflood to increase recovery of the oil in place. The Company also consolidated its interest in the area through an acquisition completed in the fourth quarter of 2017.

Including the acquisition for gross consideration of $7.25 million before customary adjustments, Questerre invested $8.79 million at Antler (2016: $0.54 million) with daily production averaging 179 bbl/d (2016: 209 bbl/d). Total proved and probable reserves at December 31, 2017 were estimated at 2.02 MMbbls (2016: 1.16 MMbbls) with a before income tax NPV-10% of $48.72 million (2016: $31.25 million). The Company currently holds 12,690 net acres in the Antler area.

The acquisition consisted of approximately 180 bbls/d of light oil production. Acquired assets include 3D seismic data over the producing acreage. The proved and probable reserves associated with these assets were assessed at 0.93 MMbbls at December 31, 2017.

In 2018, Questerre plans to continue work on production optimization and the pilot waterflood.

St. Lawrence Lowlands, Quebec

Following the introduction of the *Petroleum Resources Act* to govern the development of petroleum resources, including shale gas, in Quebec, the provincial government introduced draft hydrocarbon and environmental regulations during 2017. This follows almost six years of public consultations and extensive studies on the oil and natural gas industry in Quebec.

In March 2017, the Quebec Government passed into law 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*. One of the key features of Bill 102 is to establish a simplified and modulated authorization process based on the environmental risks associated with a project. Bill 102 also includes changes to various provisions of Quebec's *Environmental Quality Act* governing, in particular, contaminated lands, residual materials and hazardous materials. The majority of the changes introduced by Bill 102 entered into force on March 23, 2018. In February 2018, the Quebec Government published several draft regulations in the Gazette officielle du Québec to implement some of the changes introduced by Bill 102. The majority of such regulations will come into force by the end of 2018.

In September 2017, the Ministry of Natural Resources published the proposed regulations to govern oil and gas activities in the province. The draft regulations are required for the implementation of the *Petroleum Resources Act*.

The purpose of the *Petroleum Resources Act* is: (i) to replace the current oil & gas statutory framework set by the *Quebec Mining Act*; and (ii) to govern the development of petroleum resources while ensuring the safety of persons and property, environmental protection and optimal recovery of the resource, in compliance with the greenhouse gas emission reduction targets set by the Quebec Government. The *Petroleum Resources Act* will come into force on a date to be set by the Quebec Government, which is expected to be on or about the same time as the adoption of the final version of the draft regulations. The Company anticipates the final regulations could be released in early 2018.

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

In the first quarter of 2018, the Company published an update to the independent assessment of its Utica shale resources in Quebec (the "Quebec Resource Assessment"). The Quebec Resource Assessment was conducted by GLJ Petroleum Consultants, an independent qualified reserves evaluator, with an effective date of December 31, 2017. 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 risked Prospective Resources net to Questerre is 0.94 trillion cubic feet ("Tcf") (157 million barrels of oil equivalent ("boe")). Additionally, the Quebec Resource Assessment details the best estimate of risked Contingent Resources, net to Questerre, is 313 Bcf (52 million boe). The net present value of the risked Contingent Resources, including the development on hold and development unclarified sub categories, discounted at 10% before tax is estimated at $409 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 Quebec Resource Assessment assigned Economic Contingent Resources for approximately 16% of Questerre's acreage based on the results from several vertical and horizontal wells on its acreage that have all encountered pay in the Utica as reported by the Company in 2008 to 2010. 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. Those areas classified as development on hold 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 no certainty that any portion of the Contingent Resources will be economic to develop. Though pilot horizontal development plans have been proposed, the project evaluation scenario for the Contingent Resources is not sufficiently defined to make an investment decision to proceed to development.

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.

Significant positive factors relevant to the estimate of Questerre'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 Questerre'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 Questerre'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 natural gas operations.

While Questerre 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 Questerre's joint venture partners. There is no guarantee that they will elect to participate in the program to the extent required. Questerre 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 AIF and the press release dated March 12, 2018 available on the Company's website at www.questerre.com and on SEDAR at www.sedar.com.

Oil Shale Mining

Questerre's oil shale assets include its project in the Kingdom of Jordan ("Jordan") and its investment in Red Leaf Resources Inc. ("Red Leaf"). Red Leaf is a private Utah based company whose principal assets include the EcoShale process to produce oil and shale and oil shale leases in the state of Utah. Questerre currently owns approximately 30% of the common share capital of Red Leaf.

The Company acquired the Jordanian 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 "MEMR"). The MOU covered an area of over 380 km^2 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 extended to May 22, 2018. Upon the completion of the MOU and the submission of the required documentation to the MEMR, the Company anticipates it will enter into negotiations with the MEMR for a concession agreement. The Company will continue to hold an exclusive right to the acreage under the MOU during the term of these negotiations. In 2017, the Company high graded its acreage and reduced the area under the MOU to 265 km^2.

Following an independent resource assessment prepared by Millcreek Mining Group ("Millcreek") in accordance with NI 51-101 and the COGE Handbook effective October 1, 2016, the Company's primary objective for 2017 was to evaluate the feasibility of commercial development. For more information on the resource assessment please refer to the Company's 2016 AIF dated March 24, 2017 and press release dated October 27, 2016 available on the Company's website at www.questerre.com and www.sedar.com.

The economic feasibility work involves assessing multiple retorting processes specifically for the Jordanian oil shale. This includes two processes that have been proven at commercial scale. Also under evaluation is the EcoShale process developed by Red Leaf. With Questerre, Red Leaf has been redesigning the EcoShale process to focus on reusable capsules. Red Leaf estimates that using large steel vessels similar to those used in coker facilities in refineries instead of the original single use earthen capsule could materially reduce costs.

In addition to assessing the retorting component of production, Questerre commissioned engineering studies to evaluate the three other components - mining and preparation of the ore, infrastructure, including power and other utilities, and upgrading of the produced oil including a marketing study.

Questerre recently completed an internal review of the retorting processes and the engineering studies. Based on the unique characteristics of the Jordanian shale, the Company believes the re-designed EcoShale process could be the most efficient. Early in 2018, the Company engaged a third party engineering firm to integrate all the studies and validate its work. Questerre anticipates this report will be completed in the third quarter of 2018.

During the year, Questerre acquired additional Red Leaf common shares for US$7.52 million. The Company currently holds 132,293 common shares, representing approximately 30% of the common share capital of Red Leaf. Questerre also acquired 288 Series A Preferred Shares, representing less than 0.5% of the issued and outstanding preferred share capital of Red Leaf, for US$0.16 million. For more information, see Note 7 to the Financial Statements.

In addition to its EcoShale process and its oil shale leases in Utah, Red Leaf holds US$104 million in cash and no debt as of December 31, 2017. In addition to common shares, Red Leaf's equity capital includes convertible preferred shares with dividends accruing at 8% per annum compounded annually. As at December 31, 2017, the Series A preferred shares are entitled to a priority amount of US$83.5 million on the occurrence of a defined liquidation event, including certain reorganizations, takeovers, the sale of all or substantially all the assets of the company and shareholder distributions.

Corporate

The Company completed a series of private placements during the year for gross proceeds of approximately $56 million.

In February 2017, the Company issued 30.8 million Common Shares at $0.79 per Common Share for gross proceeds of approximately $24.65 million and 1.41 million Common Shares at $0.49 per Common Share for gross proceeds of $0.69 million. The second issuance relates to a private placement completed in November 2016 for the same issue price. In October 2017, the Company issued 34.9 million Common Shares at $0.89 per Common Share for gross proceeds of approximately $31 million.

Following a review conducted in the fourth quarter of 2017, effective January 2018, the Company's credit facilities with a Canadian chartered bank were maintained at $18 million. The facilities consist primarily 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. As at December 31, 2017, $13.90 million was drawn under the facility. The next scheduled review of these facilities is in the second quarter of 2018.

Drilling Activities

In 2017, Questerre participated in the drilling of 7 (1.60 net) wells in the Kakwa area. 4 (0.92 net) wells were placed on production in 2017 and 3 (0.68 net) wells will be completed and placed on production in 2018.

Production

	2017			2016		
	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)
Alberta	600	3,278	1,146	547	3,360	1,107
Saskatchewan	179	-	179	209	-	209
Manitoba	42	-	42	45	-	45
British Columbia	-	72	12	-	76	12
	821	3,350	1,379	801	3,436	1,373

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

With the majority of the Kakwa joint venture wells coming on stream in the latter half of the year, production on average remained relatively unchanged over the prior year.

Representing over 80% of corporate volumes, production from the area increased from 673 boe/d in the first quarter (2016: 1,159 boe/d) to 1,358 boe/d (2016: 967 boe/d) in the fourth quarter with an average of 1,123 boe/d (2016: 1,036 boe/d). During the year, Questerre participated in the drilling of all seven (1.60 net) wells spud on the joint venture acreage. By comparison, in 2016, to preserve financial liquidity, the Company participated in the drilling of only three (0.75 net) out of the seven wells spud.

Questerre's oil and liquids production represents light crude oil and natural gas liquids and natural gas production represents primarily shale gas. Consistent with prior years, the oil and liquids weighting remained unchanged at about 60%. This generally approximates the relative weighting of natural gas liquids, primarily condensate, to natural gas from Kakwa.

Liquids production also includes volumes from Antler, Saskatchewan and Pierson, Manitoba. These volumes decreased over the prior year due to natural declines. At Antler, these declines were partially offset by a workover and optimization program as well as an acquisition of approximately 180 bbls/d completed in the fourth quarter of the year.

Based on its planned participation in up to six gross wells on the Kakwa joint venture acreage largely in the second half of this year, the Company anticipates its production to increase in 2018.

2017 Financial Results

Petroleum and Natural Gas Sales

	2017			2016		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Alberta	$ 13,267	$ 2,913	$ 16,180	$ 9,148	$ 3,152	$ 12,300
Saskatchewan	4,218	-	4,218	3,968	-	3,968
Manitoba	911	-	911	796	-	796
British Columbia	4	48	52	7	49	56
	$ 18,400	$ 2,961	$ 21,361	$ 13,919	$ 3,201	$ 17,120

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

Year over year, petroleum and natural gas sales increased by 25% or $4.24 million due to materially higher crude oil and liquids prices. This was marginally offset by the lower natural gas revenue due to lower natural gas prices.

Pricing

	2017	2016
Benchmark prices:		
Natural Gas - AECO, daily spot ($/Mcf)	2.26	2.16
Crude Oil - Canadian Light Sweet Blend ($/bbl)	65.86	54.28
Realized prices:		
Natural Gas ($/Mcf)	2.42	2.55
Crude Oil and Natural Gas Liquids ($/bbl)	61.28	47.51

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

Crude oil prices improved materially over the prior year with the benchmark West Texas Intermediate ("WTI") averaging US$52/bbl in 2017 compared to US$43/bbl in 2016.

Prices in the first quarter remained relatively strong following OPEC's decision to cut oil production in late 2016. Throughout the next two quarters, prices were negatively impacted by concerns of growing rig counts and increasing oil production in the United States, particularly from the Permian Basin. Prices improved materially in the fourth quarter partly due to the extension of the OPEC/Russia production cuts, reducing inventories, and signs of growing global demand. In Canada, prices were affected by an improving exchange rate and a volatile differential. On average, the differential between WTI and the benchmark Canadian Light Sweet blend ("MSW") decreased from a premium US$0.25/bbl to a discount of US$0.77/bbl. Questerre anticipates this discount will remain volatile during the coming year.

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

Natural gas prices increased over the year with the benchmark Henry Hub averaging US$2.99/MMBtu compared to an average price of US$2.48/MMBtu in 2016.

Dry natural gas production in the US continued to increase in 2017, driven in part by growth in the Marcellus and Utica shale in the northeast US. Expected demand growth for industrial and power usage was slower than expected, due to the increase in the use of renewables for power generation. This was partially offset by exports primarily to Mexico. In Alberta, high storage levels, maintenance issues on the main pipeline and limited access to markets outside the province increased the differential materially and resulted in negative gas prices in the province in the third quarter of the year.

Higher heat content production from Kakwa contributed to a realized price of $2.42/Mcf in 2017 (2016: $2.55/Mcf) compared to an AECO average price of C$2.26/Mcf (2016: $2.16/Mcf).

Royalties

($ thousands)		2017		2016
Alberta	$	676	$	546
Saskatchewan		257		294
Manitoba		160		97
	$	1,093	$	936
% of Revenue:				
Alberta		4%		4%
Saskatchewan		6%		7%
Manitoba		18%		12%
Total Company		5%		5%

Consistent with the increase in oil and gas revenue over the prior year, gross royalties increased from $0.94 million to $1.09 million. As a percentage of the revenue this remained constant at 5%.

The royalties in Alberta, specifically at Kakwa, include gross overriding royalties and Crown royalties net of credits for processing the Crown's share of production through the Company's joint facilities and incentive programs.

Production in Kakwa benefits from several legacy 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, that took effect on 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.

The increase on production from Manitoba reflects the higher proportion of volumes from freehold lands that attract a higher rate compared to Crown lands.

Operating Costs

($ thousands)	**2017**	2016
Alberta	**$ 7,754**	$ 6,142
Saskatchewan	**1,938**	1,105
Manitoba	**248**	301
British Columbia	**90**	104
	$ 10,030	$ 7,652
$/boe:		
Alberta	**18.51**	15.16
Saskatchewan	**29.66**	14.44
Manitoba	**16.16**	18.26
British Columbia	**24.56**	23.67
Total Company	**19.93**	15.23

Operating costs increased by just over 30% to $10.03 million from $7.65 million in 2016 due to higher costs at Kakwa and Antler.

On a unit of production basis, with similar production volumes in both years, operating costs were also 30% higher this year at $19.93/boe from $15.23/boe last year. In Alberta, Kakwa costs were higher primarily for chemical treatment and unutilized processing and transportation commitments. While the installation of the regenerative amine system reduced chemical costs, additional costs were incurred for further treating. Unutilized demand charges averaged approximately $2.3 million or just under 30% of operating costs at Kakwa. The Company anticipates these will decrease as additional volumes are brought on production in the second half of 2018.

At Antler, $0.40 million was spent to workover wells that restored production but did not result in an increase in proved and probable reserves. Additionally, higher costs were incurred in 2017 for maintenance of the battery as well as rehabilitation costs associated with a spill. With the vast majority of costs at Antler as fixed, Questerre believes these costs on a boe basis will decline in 2018 with the increased production volumes attributable to the acquisition completed late last year.

General and Administrative Expenses

($ thousands)	**2017**	2016
General and administrative expenses, gross	**$ 4,119**	$ 3,735
Capitalized expenses and overhead recoveries	**(976)**	(974)
General and administrative expenses, net	**$ 3,143**	$ 2,761

Gross general and administrative expenses ("G&A") in 2017 increased by approximately 10% due to higher legal, transfer agent and consulting fees. This was offset by a 5% decrease in salaries and directors' fees over the prior year. Capitalized expenses and overhead recoveries remain unchanged and reflect the administrative costs associated directly with the Company's assets, particularly in Quebec and Jordan.

Depletion, Depreciation, Impairment and Lease Expiries

For the year ended December 31, 2017, the Company reported depletion and depreciation expense of $9.72

million compared to $8.86 million in 2016. The higher expense reflects the increased capital costs and marginally higher production in the current year. On a per unit basis, depletion increased slightly to $17.95/boe from $17.62/boe in 2016 with increased production volumes in the current year from cash generating units ("CGUs") with higher finding and development costs.

At December 31, 2017, 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, reserves and discount rates.

Based on this review, the Company's Montney 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. As a result of lower commodity prices and an increase in the discount rate used for the Montney CGU due to higher expected equity returns for Montney producers, the Company recorded an impairment charge of $12.30 million. Of this amount $11.98 million relates to the Montney CGU and $0.32 million related to its Other Alberta CGU. In 2016, due the introduction of new hydrocarbon legislation and the updated resource assessment in Quebec, the Company recognized a reversal of the impairment loss of $23.50 million recorded in 2015 for these assets.

The Company also recorded an expense of $7.12 million (2016: $17.84 million) primarily related to expired acreage in the Wapiti area of Alberta where the Company has no future plans for development. During the year, the Company also recorded a gain of $3.66 million (2016: nil) on the disposition of shallow exploration rights in the Kakwa area.

With respect to its investment in Red Leaf, during the year, the Company reversed a previously recorded impairment charge of $2.34 million (2016: nil). The reversal relates to the increase in fair value of the Red Leaf common shares held by Questerre prior to the acquisition. The Company also recorded an expense of $3.40 million for the year (2016: nil) representing its proportionate share of the net loss realized by Red Leaf during the period commencing from its initial acquisition to the end of the year. The expense recorded also reflects the impact of the Red Leaf preferred share dividends on the carrying value of the Red Leaf common shares.

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 $0.41 million for the year ended December 31, 2017 (2016: $0.12 million).

Deferred Taxes

The Company reported a deferred tax expense of $5.53 million for 2017 compared to an expense of $0.45 million for the prior year.

The expense reflects the increase in its valuation allowance for its deferred tax asset at year end. In 2017, 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 2017.

Other Income and Expenses

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

The Company recorded an unrealized gain of $1.12 million (2016: loss of $1.53 million) and a realized loss of $0.07 million (2016: gain of $1.33 million) for its risk management contracts. No contracts were outstanding as of December 31, 2017.

Questerre reported interest expense of $0.62 million for the year ended December 31, 2017 and $0.91 million for the prior year. The expense primarily relates to the interest on its credit facilities with a Canadian chartered bank.

The Company recorded a loss on foreign exchange, net of deferred tax, through other comprehensive income (loss) of $0.86 million for the year ended December 31, 2017 (2016: $0.07 million). The changes are due to fluctuations in the exchange rate relating to its US dollar investments, primarily Red Leaf.

Total Comprehensive Income (Loss)

Questerre's total comprehensive loss was $25.68 million for 2017 compared to income of $0.10 million in 2016. The Company's change in total comprehensive income is attributable mainly to the higher operating costs, impairment and loss on equity investment compared to the prior year. Furthermore, in 2016 the Company recorded the reversal of an impairment charge of $22.9 million primarily related to its assets in Quebec.

Net Income (Loss) Per Share

Questerre's basic net loss per share of $0.07 compared to nil per share in 2016. Questerre's net loss was $24.82 million in 2017 and the Company reported net income of $0.17 million in 2016.

Capital Expenditures

($ thousands)		2017		2016
Alberta	$	22,158	$	11,909
Saskatchewan		1,541		540
Manitoba		89		39
Jordan		833		1,260
Quebec		640		470
		25,261		14,218
Acquisitions (Saskatchewan)		6,935		-
Proceeds from disposition		(4,450)		-
Total	$	27,746	$	14,218

In 2017, Questerre incurred net capital expenditures of $27.75 million as follows:

- $22.16 million was invested in Alberta to participate in the drilling and completion of wells targeting condensate-rich natural gas from the Montney and related infrastructure costs;
- $1.54 million was invested in Saskatchewan to optimize production from wells that resulted in increased reserves; and
- $0.83 million was invested in Jordan to assess the Company's oil shale acreage.

During the year, the Company completed an acquisition in the Antler area of Saskatchewan for $6.94 million. The Company also disposed of exploration and evaluation assets in the Kakwa area for gross proceeds of $4.45 million.

In 2016, Questerre reduced its capital investment to preserve liquidity. It incurred net capital expenditures of $14.22 million as detailed below:

- $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; and
- $1.26 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 January 2018 following a review, the Company's credit facilities remained at $18 million from the last scheduled review. At December 31, 2017, $13.90 million (December 31, 2016: $22.89 million) was drawn on the credit facility and the Company is in compliance with all of 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, 2017 was 2.66 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 2018.

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 surplus, including amounts due under its credit facilities, of $9.65 million at December 31, 2017, as compared to a deficit of $17.02 million at December 31, 2016. Management believes that with its private placements completed in the year for gross proceeds of approximately $56 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 should 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, 2017. 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 MD&A and the AIF.

Cash Flow from Operating Activities

Net cash from operating activities for the year ended December 31, 2017 and 2016 was $14.66 million and $6.72 million, respectively. While adjusted funds flow from operations decreased in 2017, a significant increase in non-cash working capital in the current year contributed to the higher net cash from operating activities in 2017 compared to the prior year.

Cash Flow used in Investing Activities

Cash flow used in investing activities increased to $33.18 million in 2017 from $19.68 million in 2016. For the year ended December 31, 2017, the Company incurred capital expenditures of $25.26 million compared to $14.22 million for the same period in 2016. Additionally, the Company concluded an acquisition of producing properties at Antler for $6.94 million and increased its investment in Red Leaf by $10.33 million. This was partially offset by an asset disposition in the Kakwa area for gross proceeds of $4.45 million and an increase in related non-cash working capital of $4.89 million compared to a decrease of $5.46 million in the prior year.

Cash Flow provided by Financing Activities

Cash flow provided by financing activities increased from $20.89 million in 2016 to $46.08 million in 2017. The increase reflects the private placements completed by the Company for gross proceeds of approximately $56 million and drawdowns under the Company's credit facilities, net of repayments. In 2016, the Company realized gross proceeds of $13.22 million from the issuance of equity and a net increase of $8.35 million from drawdowns under its 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, 2017, 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 29, 2018**	**December 31, 2017**	December 31, 2016
Common Shares	**388,956**	**385,331**	308,274
Stock Options	**21,327**	**21,387**	14,856
Warrants	**-**	**3,566**	13,124
Weighted average Common Shares			
Basic		**350,055**	278,662
Diluted		**350,055**	280,410

A summary of the Company's stock option activity during the years ended December 31, 2017 and 2016 follows:

	December 31, 2017		December 31, 2016	
	Number of Options *(thousands)*	**Weighted Average Exercise Price**	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	**14,856**	**$0.41**	19,982	$0.72
Granted	**6,900**	**0.69**	4,100	0.18
Forfeited	**(232)**	**0.52**	(4,289)	0.47
Expired	**(90)**	**0.70**	(3,260)	1.85
Exercised	**(47)**	**0.62**	(1,677)	0.60
Outstanding, end of period	**21,387**	**$0.50**	14,856	$0.41
Exercisable, end of period	**9,180**	**$0.50**	5,939	$0.55

Commitments

A summary of the Company's net commitments at December 31, 2017 follows:

($ thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation, Marketing and Processing	$ 4,728	$ 3,990	$ 3,990	$ 3,990	$ 3,990	$ 15,962	$ 36,650
Office Leases	116	99	90	-	-	-	305
	$ 4,844	$ 4,089	$ 4,080	$ 3,990	$ 3,990	$ 15,962	$ 36,955

Questerre has no capital commitments in 2018. 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, 2017.

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. The Company anticipates that future development of its Quebec assets will require significant additional capital to be financed through among other sources, future equity issuances or asset dispositions.

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 natural 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, 2017, the Company had no outstanding commodity risk management contract in place.

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 natural 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 natural 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. Since December 31, 2016, the recoverability of deferred tax assets is 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 equity investment and assesses for indicators of impairment at each period end. For the purposes of impairment testing, the Company measures the fair value of Red Leaf by valuation techniques such as the net asset value approach.

Accounting Standards Changes

Changes in Accounting Policies for 2017

The Company adopted amendments to IAS 7, Statement of Cash Flows, which provide disclosures on evaluating changes in the liabilities arising from financing activities during the year ended December 31, 2017. See Note 13 on IAS 7 adoption.

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 this standard 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. The standard may be applied retrospectively or using a modified retrospective approach. The Company has performed an initial assessment of IFRS 15 and plans to adopt the standard under the modified retrospective approach on January 1, 2018. Under this method, comparative figures are not restated and the cumulative effect of initially applying the standard (if any) would be recognized at the date of adoption. The Company will be required to disclose additional information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including a disaggregation of revenue by product type. The Company's initial assessment that adoption of IFRS 15 will not have a material impact on the Company's Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) is made as of the date of these annual financial statements and may change as new publications or interpretations of the new standard become available. The evaluation of all potential measurement and disclosure impacts is ongoing.

IFRS 9 *Financial Instruments*

In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments ("IFRS 9"). The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than the statement of income. The Company has determined that adoption of IFRS 9 will result in changes to the classification of the Company's financial assets but will not change the classification of the Company's financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. Questerre has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9.

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, 2017.
- 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, 2017 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, 2017 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 2017 Results

Questerre's cash from operating activities decreased to $1.27 million for the quarter ended December 31, 2017 from $2.70 million for the same period in 2016. This is attributable to the decrease in non-cash working capital, which offsets the higher petroleum and natural gas revenue in the last quarter of 2017. The increase in adjusted funds flow from operations to $2.55 million from $1.94 million is due to higher petroleum and natural gas revenue in the period compared to the prior year.

Petroleum and natural gas revenue increased materially from $4.57 million for the three months ended December 31, 2016 to $7.30 million for the same period in 2017 due to higher production volumes and prices. Production volumes increased by over 35% to 1,714 boe/d from 1,261 boe/d due to Company's full participation in the 2017 joint venture drilling program at Kakwa. The Company also completed an acquisition of producing assets in the Antler area during the fourth quarter. By comparison in 2016, the Company selectively participated in the joint venture program at Kakwa. The Company's realized price for oil and natural gas liquids was $66.98/bbl for the fourth quarter of 2017 and $51.12/bbl for the same period in 2016.

Operating costs were $3.46 million or $21.96/boe for the three months ended December 31, 2017 compared to $1.67 million or $14.38/boe for the same period last year. The increase in operating costs is due to the higher production in the current year and higher costs specifically in the Kakwa area for chemical and unutilized take or pay commitments. Additionally during the quarter, the Company incurred $0.4 million in operating costs at Antler to restore wells to production that did not increase reserves.

During the quarter, the Company realized a loss of $1.05 million related to its investment in Red Leaf (2016: nil).

Total comprehensive loss for the three months ended December 31, 2017 was $17.96 million compared to income of $3.67 million for the same period in 2016. The Company's change in total comprehensive income is attributable mainly to the higher operating costs, impairment and loss on equity investment compared to the prior year. The income in the prior year was largely due to the reversal of prior impairment charge of $22.93 million related to the Company's assets in Quebec.

Quarterly Financial Information

($ thousands, except as noted)	**December 31, 2017**	September 30, 2017	June 30, 2017	March 31, 2017
Production (boe/d)	**1,714**	1,643	1,037	1,123
Average Realized Price ($/boe)	**46.30**	36.03	44.34	43.82
Petroleum and Natural Gas Sales	**7,302**	5,446	4,184	4,429
Adjusted Funds Flow from Operations	**2,552**	1,938	880	1,411
Basic and Diluted ($/share)	**-**	-	-	-
Net Profit (Loss)	**(18,036)**	(2,641)	(3,621)	(523)
Basic and Diluted ($/share)	**(0.05)**	(0.01)	(0.01)	(0.01)
Capital Expenditures, net of acquisitions and dispositions	**14,976**	4,906	2,544	5,320
Working Capital Surplus (Deficit)	**9,648**	(7,559)	(3,184)	3,274
Total Assets	**217,214**	198,904	205,672	205,640
Shareholders' Equity	**170,738**	158,204	160,069	163,888
Weighted Average Common Shares Outstanding				
Basic (thousands)	**383,093**	346,685	345,408	324,426
Diluted (thousands)	**383,093**	346,685	345,408	324,426

($ 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 ($/boe)	39.43	34.91	34.17	28.79
Petroleum and Natural Gas Sales	4,574	4,095	4,423	4,029
Adjusted Funds Flow from Operations (1	1,943	1,447	1,916	1,740
Basic and Diluted ($/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

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

- Petroleum and natural gas revenues and adjusted funds flow from operations have fluctuated with production volumes and realized commodity prices.
- Production volumes reflect the capital investment in drilling and completing wells at Kakwa in preceding quarters. Following increased investment in Kakwa in 2017, production has grown to 1,714 boe/d in the most recent quarter. The Company plans to continue to invest at Kakwa, subject to commodity prices and results, and expects a commensurate increase in production. Additionally, the Company expects production to increase following the acquisition of producing assets in the Antler area in the fourth quarter of 2017.
- The level of capital expenditure over the quarter has varied largely due to the timing and number of wells drilled and completed for the Kakwa asset as well as the timing of the infrastructure investment.
- The working capital deficit has generally increased when capital expenditures and other investments have been higher than adjusted funds flow from operations and cash from financing activities.
- Shareholders' equity increased in the quarters ended December 31, 2016, March 31, 2017 and December 31, 2017 as a result of the equity issuances completed by the Company during those periods.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the year ended December 31, 2017, other than commitments as disclosed.

Related Party Transactions

The Company did not engage in any related party transactions during the year ended December 31, 2017, other than key management compensation as disclosed.

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 29, 2018

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, 2017 and December 31, 2016 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, 2017 and December 31, 2016 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 29, 2018

Consolidated Balance Sheets

($ thousands)	Note		December 31, 2017		December 31, 2016
Assets					
Current Assets					
Cash and cash equivalents	5	$	**35,836**	$	8,275
Accounts receivable	6		**3,780**		2,339
Deposits and prepaid expenses			**556**		626
			40,172		11,240
Investments	7		**9,109**		490
Property, plant and equipment	8		**98,893**		87,125
Exploration and evaluation assets	9		**53,675**		58,915
Goodwill			**2,346**		2,346
Deferred tax assets	10		**13,019**		17,645
		$	**217,214**	$	177,761
Liabilities					
Current Liabilities					
Accounts payable and accrued liabilities		$	**16,623**	$	5,370
Current portion of risk management contracts	6		**-**		1,117
Credit Facilities	13		**13,901**		22,888
			30,524		29,375
Other Liability	20		**3,487**		-
Asset retirement obligation	12		**12,465**		8,726
			46,476		38,101
Shareholders' Equity					
Share capital	14		**414,995**		359,151
Contributed surplus			**18,171**		17,254
Accumulated other comprehensive income			**(724)**		138
Deficit			**(261,704)**		(236,883)
			170,738		139,660
		$	**217,214**	$	177,761

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

		For the years ended December 31,	
($ thousands, except per share amounts)	Note	2017	2016
Revenue			
Petroleum and natural gas sales	15	$ 21,361	$ 17,120
Royalties		(1,093)	(936)
Petroleum and natural gas revenue, net of royalties		20,268	16,184
Expenses			
Direct operating		10,030	7,652
General and administrative		3,143	2,761
Depletion and depreciation	8	9,723	8,861
Gain on sale of exploration and evaluation asset		(3,657)	-
Recovery of impairment on investment	7	(2,336)	-
Gain on acquisition of preferred shares	7	(274)	-
Impairment of assets	8,9	12,303	(22,925)
Lease Expiries		7,122	17,838
Loss (gain) on risk management contracts	6	(1,049)	195
Loss on equity investment	7	3,450	-
Share based compensation	11	411	122
Accretion of asset retirement obligation	12	173	142
Interest expense		599	912
Other (income) expense		(77)	12
Income (loss) before taxes		(19,293)	614
Deferred tax expense	10	5,528	445
Net Income (Loss)		(24,821)	169
Other Comprehensive Loss, Net of Tax			
Items that may be reclassified subsequently to profit or loss:			
Loss on foreign exchange	7	(740)	(13)
Foreign currency translation adjustment		(122)	(30)
Reclass to net loss on write-down of investments	7	-	(28)
		(862)	(71)
Total Comprehensive Income (Loss)		$ (25,683)	$ 98
Net Loss per Share			
Basic and diluted	14	$ (0.07)	$ -

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

Consolidated Statements of Changes in Equity

($ thousands)	For the years ended December 31, 2017	2016
Share Capital		
Balance, beginning of year	$ 359,151	$ 347,345
Private Placements	55,988	11,279
Warrants exercised	1,912	15
Options exercised	29	1,006
Share issue costs (net of tax)	(2,085)	(494)
Balance, end of year	414,995	359,151
Contributed Surplus		
Balance, beginning of year	17,254	16,951
Reclassification of share based compensation	917	303
Balance, end of year	18,171	17,254
Accumulated Other Comprehensive Income		
Balance, beginning of year	138	209
Other comprehensive loss	(862)	(71)
Balance, end of year	(724)	138
Deficit		
Balance, beginning of year	(236,883)	(237,052)
Net income (loss)	(24,821)	169
Balance, end of year	(261,704)	(236,883)
Total Shareholders' Equity	$ 170,738	$ 139,660

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

Consolidated Statements of Cash Flows

($ thousands)	Note	For the years ended December 31, 2017	2016
Operating Activities			
Net loss		$ (24,821)	$ 169
Adjustments for:			
Depletion and depreciation	8	9,723	8,861
Recovery of impairment on investment		(2,336)	-
Gain on acquisition of preferred shares		(274)	-
Impairment of assets & lease expiries	8,9	19,425	(5,087)
Gain on sale of exploration and evaluation asset	8	(3,657)	-
Unrealized (gain) loss on risk management contracts	6	(1,117)	1,531
Loss on equity investment		3,450	-
Share based compensation	11	411	122
Accretion of asset retirement obligation	12	173	142
Deferred tax expense	10	5,528	445
Interest expense		599	912
Other items not involving cash		(122)	(32)
Abandonment expenditures	12	(201)	(18)
Adjusted funds flow from operations		6,781	7,045
Interest paid		(615)	(912)
Change in non-cash working capital	18	8,495	586
Net cash from operating activities		14,661	6,719
Investing Activities			
Property, plant and equipment expenditures	8	(7,935)	(3,301)
Exploration and evaluation expenditures	9	(17,326)	(10,917)
Purchase of investment	7	(10,330)	-
Acquisition of plant, property and equipment	8	(6,935)	-
Sale of exploration and evaluation assets		4,450	-
Change in non-cash working capital	18	4,892	(5,457)
Net cash used in investing activities		(33,184)	(19,675)
Financing Activities			
Proceeds from issue of share capital		57,928	13,218
Increase in credit facilities		30,880	32,246
Repayment of credit facilities		(39,867)	(23,900)
Share issue costs		(2,857)	(676)
Net cash from financing activities		46,084	20,888
Change in cash and cash equivalents		27,561	7,932
Cash and cash equivalents, beginning of year		8,275	343
Cash and cash equivalents, end of year		$ 35,836	$ 8,275

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, 2017 and 2016 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 29, 2018, 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 the 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

All of Questerre's petroleum and natural gas reserves 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 will change to reflect updated information. Reserve 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 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.

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.

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

Share based compensation

The Company has a stock option plan enabling employees, officers and directors to receive Class “A” Common voting shares (“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, 2017, 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 holds investments in certain private companies including its investment in Red Leaf Resources Inc. ("Red Leaf"). The Company measures the fair market value of Red Leaf by valuation techniques such as net asset value analysis. 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.

The Company uses the equity method of accounting to reflect its ownership in Red Leaf. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of Red Leaf's income or loss, less distributions received. The Company is deemed to have significant influence in Red Leaf on the basis that it holds more than 20% of the voting power and the ability to participate in the decision making process of Red Leaf through its current Board representation.

Refer to Note 7 for the carrying amounts 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.

<u>Transactions eliminated on consolidation</u>

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.

<u>Financial assets and liabilities at fair value through profit or loss</u>

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.

<u>Available for sale</u>

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

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. Gains and losses on exploration and evaluation assets are recognized on disposal through the income statement.

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.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future profit (loss) can be affected as a result of changes in future depletion and depreciation or impairment. Refer to Note 8 for details on the business combinations completed during the year ended December 31, 2017.

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.

4. Changes in Accounting Policies and Disclosures

Changes in Accounting Policies for 2017

The Company adopted amendments to IAS 7, Statement of Cash Flows, which provide disclosures on evaluating changes in the liabilities arising from financing activities during the year ended December 31, 2017. See Note 13 on IAS 7 adoption.

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 this standard on its consolidated financial statements.

IFRS 15 *Revenue From Contracts With Customers*

In May 2014, the IAS 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. The standard may be applied retrospectively or using a modified retrospective approach. The Company has performed an initial assessment of IFRS 15 and plans to adopt the standard under the modified retrospective approach on January 1, 2018. Under this method, comparative figures are not restated and the cumulative effect of initially applying the standard (if any) would be recognized at the date of adoption. The Company will be required to disclose additional information regarding the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including a disaggregation of revenue by product type. The Company's initial assessment that adoption of IFRS 15 will not have a material impact on the Company's Consolidated Statement of Profit (Loss) and Comprehensive Income (Loss) is made as of the date of these annual financial statements and may change as new publications or interpretations of the new standard become available. The evaluation of all potential measurement and disclosure impacts is ongoing.

IFRS 9 *Financial Instruments*

In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments ("IFRS 9"). The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than the statement of income. The Company has determined that adoption of IFRS 9 will result in changes to the classification of the Company's financial assets but will not change the classification of the Company's financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. Questerre has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9.

5. Cash and Cash Equivalents

($ thousands)	**December 31, 2017**	December 31, 2016
Bank balances	**$ 1,871**	$ 7,959
Short-term bank deposits	**33,965**	316
	$ 35,836	$ 8,275

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, 2017 included cash and cash equivalents, accounts receivable, deposits, investments, credit facilities and accounts payable and accrued liabilities. As at December 31, 2017, 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 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.

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 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 natural 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, 2017		December 31, 2016
Current	$	3,076	$	2,058
31 - 60 days		204		27
61 - 90 days		79		51
>90 days		573		355
Allowance for doubtful accounts		(152)		(152)
	$	3,780	$	2,339

The Company does not anticipate any material 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 natural 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.

Commodity price risk

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, 2017, the Company had no outstanding commodity risk management contracts.

The net risk management position is as follows:

($ thousands)	**December 31, 2017**	December 31, 2016
Risk Management Liabilities		
Current portion	**$ -**	$ 1,117

For the year ended December 31, 2017, the Company recorded a realized loss of $0.07 million and unrealized gain of $1.12 million related to risk management contracts. The Company recorded an unrealized loss of $1.53 million and a realized gain of $1.33 million for the year ended December 31, 2016.

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, 2017, 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, 2017, the Company had credit facilities outstanding of $13.90 million (December 31, 2016: $22.89 million).

f) Capital management

The Company believes with its private placements completed in 2017 and expected positive adjusted funds flow from operations in the near future it 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.

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, 2017**		December 31, 2016
Credit facilities	**$**	**13,901**	$	22,888
Shareholders' equity		**170,738**		139,660

7. Investment in Red Leaf

Red Leaf is a private Utah based oil shale and technology company whose principal assets are its proprietary EcoShale technology to recover oil from shale and its oil shale leases in the state of Utah.

In the second quarter of 2017, the Company entered into agreements to increase its common share ownership in Red Leaf from approximately 6% to 30% for gross consideration of US$7.52 million.

The acquisition was completed in three tranches with payments to the vendors of US$4.92 million for the first tranche in the second quarter, US$1.3 million for the second tranche and US$1.3 million for final tranche in the third quarter of 2017. Questerre currently holds 132,293 common shares, representing approximately 30% of the common share capital of Red Leaf.

During the third quarter of 2017, Questerre also acquired 288 Series A Preferred Shares of Red Leaf representing less than 0.5% of the issued and outstanding preferred shares capital of Red Leaf for gross consideration of US$0.16 million.

Questerre has determined its investment in Red Leaf will be accounted for using the equity method. This is based on several criteria including its current equity interest in Red Leaf and ability to participate in the decision making process of Red Leaf through its current Board representation.

As a result of the acquisition of Red Leaf common shares, Questerre evaluated the fair value of the Red Leaf common shares held prior to the acquisition. This resulted in a $2.34 million reversal of a previously recorded impairment in the year ended December 31, 2014. The Company measured the fair market value of its investment using a net asset valuation approach. The net assets are estimated as the net current assets of Red Leaf less US$83.5 million representing the original issue price plus accrued but unpaid dividends of the issued and outstanding Series A Preferred Shares of Red Leaf as of December 31, 2017. No value was assigned to the non-current assets of Red Leaf for the purposes of determining the fair value of the Company's investment.

The Company also evaluated the fair value of the preferred shares based on the face value and accrued but unpaid dividends as of December 31, 2017. This resulted in a fair value adjustment of $0.26 million for the year ended December 31, 2017.

($ thousands)		December 31, 2017		December 31, 2016
Investment	$	12,510	$	490
Equity loss on investment		(3,401)		-
	$	9,109	$	490

The equity loss on investment represents the Company's proportionate share of the net loss realized by Red Leaf during the period commencing from its initial acquisition on May 11, 2017 to December 31, 2017.

The assets, liabilities and net loss of Red Leaf as of December 31, 2017 were comprised as follows:

($ thousands) [1]		
Cash and Cash Equivalents	$	130,630
Restricted Cash		4,980
Current Liabilities		1,287
Non-current liabilities		1,321
Net Loss[2]		(7,518)

[1] Converted at an exchange rate of US$1=C$1.2545

[2] For the period from May 11, 2017 to Dec 31, 2017 and converted at an average exchange rate of US$1=C$1.2795

The issued and outstanding share capital of Red Leaf as of December 31, 2017 is comprised of the following:

	Issued and Outstanding	Questerre Ownership
Common Shares	415,639	132,293
Preferred Shares	63,427	288

The Series A Preferred Shares carry voting rights and dividends accrue on a cumulative basis, whether or not declared, at a rate of 8% per annum compounding annually. On the occurrence of a defined liquidation event, including certain reorganizations, takeovers, the sale of all or substantially all the assets of the company, and shareholder distributions, the Series A Preferred shareholders are entitled to an amount representing the original issue price plus any accrued dividends. As of December 31, 2017, this priority amount is approximately US$83.5 million.

The following table sets out the changes in investment over the respective periods:

($ thousands)		December 31, 2017		December 31, 2016
Balance, beginning of year	$	490	$	632
Purchase of investment		10,330		-
Reversal of impairment		2,336		-
Preferred shares fair value adjustment		274		-
Equity loss on investment		(3,401)		-
Loss on foreign exchange		(920)		(10)
Impairment		-		(132)
Balance, end of the year	$	9,109	$	490

For the year ended December 31, 2017, the loss on foreign exchange relating to investments was $0.92

million (December 31, 2016: loss $0.01 million), which was recorded in other comprehensive income (loss) net of deferred tax of $0.11 million (December 31, 2016: $nil).

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

A reconciliation of the property, plant and equipment assets is detailed below.

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Cost or deemed cost:						
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
Additions		11,781		-		11,781
Acquisition		6,935				6,935
Transfer from exploration and evaluation assets		15,078		-		15,078
Balance, December 31, 2017	**$**	**246,806**	**$**	**1,334**	**$**	**248,140**
Accumulated depletion, depreciation and impairment losses:						
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
Depletion and depreciation		9,712		11		9,723
Impairment		12,303		-		12,303
Balance, December 31, 2017	**$**	**147,952**	**$**	**1,295**	**$**	**149,247**

($ thousands)		Oil and Natural Gas Assets		Other Assets		Total
Net book value:						
At December 31, 2016	$	87,075	$	50	$	87,125
At December 31, 2017	**$**	**98,854**	**$**	**39**	**$**	**98,893**

During the year ended December 31, 2017, the Company did not capitalize any administrative overhead or stock based compensation expense directly related to development activities (2016: $0.06 million). Included in the December 31, 2017 depletion calculation are future development costs of $172.37 million (December 31, 2016: $177.86 million). As at December 31, 2017, $1.05 million of assets under construction were included within property, plant and equipment (December 31, 2016: $2.50 million) and are not subject to depletion and depreciation.

In the fourth quarter of 2017, the Company acquired oil and gas assets in the Antler area of Saskatchewan for cash consideration of $7.25 million before closing adjustments. The purchase price was adjusted for the results of operations between the effective date of October 1, 2017 and the closing of the acquisition. The transaction has been accounted for as a business combination using the acquisition method whereby the net assets acquired and the liabilities assumed are recorded at fair value. The Company pro forma net operating revenue from the assets acquired was $1.41 million based on the estimated production from these assets and using the Company's average netback in the area for 2017. The closing adjustments included estimated net operating revenue of $0.32 million from the assets for the period from the effective date to closing of the acquisition.

($ thousands)		December 31, 2017
Property, plant and equipment	$	9,548
Decommissioning obligations		(2,298)
Fair value of net assets acquired		7,250
Cash consideration, after closing adjustments	$	6,935

In 2017, the Company reviewed the carrying amounts of its oil and natural gas assets for indicators of impairment or a reversal of previously recorded impairment due to changes in future commodity prices, future costs and reserves. Based on this review, the Company's CGUs of Montney and Other Alberta were tested for impairment in accordance with the Company's accounting policy. 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 discount rates of 10% for the Other Alberta CGU and 12% for the Montney CGU 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:

	2018	2019	2020	2021	2022	Average Annual % Change Thereafter
WTI (US$/barrel)	58.50	58.70	62.40	69.00	73.10	2.00
AECO ($/MMbtu)	2.25	2.65	3.05	3.40	3.60	2.00

Based on its assessment, the Company recorded an impairment loss of $11.97 million related to its Montney CGU and $0.36 million relating to its Other Alberta CGU. The factors that led to the impairment were a reduction in forecasted commodity prices and an increase in the discount rate for the Montney CGU. The increase in the discount rate was due to the increase in the estimated weighted average cost of capital for Montney producers and the expected return required by potential acquirers of these assets based on comparable market transactions over the last two years.

The recoverable amounts at December 31, 2017 for these CGUs are as follows:

($ thousands)	Other Alberta	Montney
Recoverable amounts	$ 212	$ 61,555

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	$ (6,870)	$ 8,075	$ (16,491)	$ 18,455

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.

A reconciliation of the movements in exploration and evaluation assets is detailed below.

($ thousands)	December 31, 2017	December 31, 2016
Balance, beginning of year	**$ 58,915**	$ 47,917
Additions	**17,753**	11,078
Transfers to property, plant and equipment	**(15,078)**	(5,740)
Undeveloped lease expiries	**(7,122)**	(17,838)
Disposition	**(793)**	-
Recovery of impairment	**-**	23,498
Balance, end of period	**$ 53,675**	$ 58,915

During the year ended December 31, 2017, the Company capitalized administrative overhead charges of $1.48 million including $0.51 million for capitalized stock based compensation expense directly related to exploration and evaluation activities. During the year ended December 31, 2016, the Company capitalized administrative overhead charges of $1.09 million and $0.18 million was recognized for capitalized stock based compensation expense directly related to these activities.

In 2017, the Company incurred an expense of $7.12 million for undeveloped land expiries in the Montney CGU (2016: $17.84 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, 2017	December 31, 2016
Net income (loss) before taxes	$ (19,293)	$ 614
Combined federal and provincial tax rate	27.00%	27.00%
Computed "expected" deferred tax expense (recovery)	(5,209)	166
Increase (decrease) in deferred taxes resulting from:		
Non-deductible differences	(200)	(50)
Deferred tax asset not recognized in year	11,035	277
Rate adjustments	(98)	52
Deferred tax expense	$ 5,528	$ 445

In the fourth quarter of 2017, 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 2017 and 2016.

The movement of the deferred tax asset is as follows:

($ thousands)	December 31, 2017	December 31, 2016
Balance, beginning of year	$ 17,645	$ 18,827
Tax recorded to statement of net profit or loss	(5,528)	(445)
Tax on share issue costs	771	182
Tax charge relating to flow through shares	-	(919)
Tax charge relating to components of other comprehensive income or loss	131	-
Balance, end of year	$ 13,019	$ 17,645

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, 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
Credited (charged) to net profit or loss		(2,697)		1,009		(311)		(3,305)
Credited to equity						771		
Balance, December 31, 2017	**$**	**3,853**	**$**	**3,365**	**$**	**731**	**$**	**6,679**

($ thousands)		Investments		Other
Deferred tax liability:				
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
Charged (credited) to net profit or loss		127		(322)
Credited to equity		(131)		-
Balance, December 31, 2017	**$**	**1,609**	**$**	**-**

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, 2017 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:

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

($ thousands)	December 31, 2017	December 31, 2016
Petroleum and natural gas properties	$ 219	$ 219
Investments	44,622	40,738
Non-capital losses	103,774	104,470
Capital losses	36,489	36,488
	$ 185,104	$ 181,915

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 purchase Common Shares 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 of the Common Shares at the day of the put notice over the exercise price of the option. 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	9,453	2.77	$0.24	4,876	2.56	$0.26
$0.31 - $0.70	8,606	3.88	0.61	1,068	2.25	0.32
$0.71 - $1.00	3,078	0.56	0.87	3,028	0.48	0.87
$1.01 - $1.40	250	1.44	1.40	208	1.44	1.40
	21,387	**2.88**	**$0.50**	**9,180**	**1.81**	**$0.50**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2017:

	December 31, 2017		December 31, 2016	
	Number of Options *(thousands)*	Weighted Average Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Price
Outstanding, beginning of period	14,856	$0.41	19,982	$0.72
Granted	6,900	0.69	4,100	0.18
Forfeited	(232)	0.52	(4,289)	0.47
Expired	(90)	0.70	(3,260)	1.85
Exercised	(47)	0.62	(1,677)	0.60
Outstanding, end of period	21,387	$0.50	14,856	$0.41
Exercisable, end of period	9,180	$0.50	5,939	$0.55

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 2017 and 2016:

	December 31, 2017	December 31, 2016
Weighted average fair value per award ($)	0.43	0.10
Volatility (%)	77.93	67.15
Forfeiture rate (%)	14.50	13.42
Expected life (years)	5.00	5.00
Risk free interest rate (%)	0.98	0.53

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 $12.47 million as at December 31, 2017 (December 31, 2016: $8.73 million) based on an undiscounted total future liability of $16.26 million (December 31, 2016: $11.37 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 1.97% (December 31, 2016: 1.56%). An inflation rate of 2.2% (December 31, 2016: 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, 2017		December 31, 2016
Balance, beginning of year	$	8,726	$	8,752
Liabilities incurred		665		161
Liabilities settled		(201)		(18)
Revisions due to change in discount and inflation rates		804		(311)
Liabilities acquired [1]		2,298		-
Accretion		173		142
Balance, end of year	$	12,465	$	8,726

[1] *See Note 8 regarding the business combination*

13. Credit Facility

As at December 31, 2017, the credit facilities include a revolving operating demand facility of $17.9 million ("Credit Facility A"), and a corporate credit card of $0.1 million ("Credit Facility C"). Credit Facility A can be used for general corporate purposes, ongoing operations and capital expenditures within Canada. 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 3.20% 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, 2017 was 2.66 and the covenant was met. At December 31, 2017, $13.90 million (December 31, 2016: $22.89 million) was drawn on Credit Facility A.

The following table reconciles the movement in the credit facilities during the year.

($ thousands)		December 31, 2017		December 31, 2016
Credit Facilities beginning of year	$	22,888	$	14,542
Drawndown from Credit Facilities		30,880		32,246
Repayment of Credit Facilities		(39,867)		(23,900)
Credit Facilities end of year	$	13,901	$	22,888

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 January 2018, Credit Facility A was renewed at $17.9 million, 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, 2017, 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, 2016	308,274		359,151
Private Placements	67,452		55,988
Options exercised	47		29
Warrants exercised	9,558		1,912
Share issue costs (net of tax effect)	-		(2,085)
Balance, December 31, 2017	**385,331**	**$**	**414,995**

The Company completed a series of private placements in 2017 for gross proceeds of approximately $56 million. In February 2017, the Company issued 30.8 million Common Shares at $0.79 per Common Share for gross proceeds of approximately $24.6 million and 1.41 million Common Shares at $0.49 per Common Share for gross proceeds of $0.60 million. In October 2017, the Company issued 34.9 million Common Shares at $0.89 per Common Share for gross proceeds of approximately $31 million.

b) Per share amounts

Basic net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2017**		December 31, 2016
Net loss ($ thousands)	**$**	**(24,821)**	$	169
Weighted average number of Common Shares outstanding (basic)		**350,055**		278,662
Basic net loss per share	**$**	**(0.07)**	$	-

Diluted net loss per share is calculated as follows:

(thousands, except as noted)		**December 31, 2017**		December 31, 2016
Net loss ($ thousands)	**$**	**(24,821)**	$	169
Weighted average number of Common Shares outstanding (basic)		**350,055**		278,662
Effect of outstanding options		**-**		1,748
Weighted average number of Common Shares outstanding (diluted)		**350,055**		280,410
Diluted net loss per share	**$**	**(0.07)**	$	-

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, 2017, 21.39 million options (December 31, 2016: 14.58 million) were excluded from the diluted weighted average number of Common Shares outstanding calculation as their effect would have been anti-dilutive.

In connection with a private placement completed in July 2016, the Company issued warrants to purchase Common Shares at a price of $0.20 per Common Share until January 28, 2018. At December 31, 2017, there were 3.57 million warrants outstanding.

15. Petroleum and Natural Gas Sales

($ thousands)		**December 31, 2017**		December 31, 2016
Oil and liquids	**$**	**18,400**	$	13,912
Natural gas		**2,961**		3,208
	$	**21,361**	$	17,120

16. Employee Salaries and Benefits

($ thousands)		**December 31, 2017**		December 31, 2016
Salaries, bonuses and other short-term benefits	**$**	**1,383**	$	1,625
Share based compensation		**917**		303
	$	**2,300**	$	1,928

17. Key Management Compensation

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

($ thousands)		**December 31, 2017**		December 31, 2016
Salaries, bonuses, director fees and other short-term benefits	**$**	**1,195**	$	1,287
Share based compensation		**830**		271
	$	**2,025**	$	1,558

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 $1.31 million at December 31, 2017. This amount does not include accelerated stock based compensation expense.

18. Supplemental Cash Flow Information

Changes in non-cash working capital are detailed below:

($ thousands)	December 31, 2017	December 31, 2016
Accounts receivable	$ (1,442)	$ 329
Deposits and prepaid expenses	69	(43)
Accounts payable and accrued liabilities	14,760	(5,157)
Change in non-cash working capital	$ 13,387	$ (4,871)
Related to:		
Operating activities	$ 8,495	$ 586
Investing activities	4,892	(5,457)
	$ 13,387	$ (4,871)

19. Commitments

A summary of the Company's net commitments at December 31, 2017 follows:

($ thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation, Marketing and Processing	$ 4,728	$ 3,990	$ 3,990	$ 3,990	$ 3,990	$ 15,962	$ 36,650
Office Leases	116	99	90	-	-	-	305
	$ 4,844	$ 4,089	$ 4,080	$ 3,990	$ 3,990	$ 15,962	$ 36,955

20. Contingent Liability

In 2011, a joint venture partner commenced legal action primarily relating to the costs of drilling two wells in Quebec in 2010. A trial to determine the amount owing by the Company is currently scheduled for December 2018 with an anticipated ruling likely in early 2019. The Company has recorded an amount of $2.4 million as a current payable on the basis that it expects a portion of the disputed amount may be settled within the next year prior to the scheduled trial. A further $3.5 million has been recorded as a contingent liability in respect of the additional potential exposure with respect to this matter. These amounts above have been accrued in prior years. The Company's potential exposure with respect to this liability is $5.9 million plus accrued interest and costs.

21. Related Party Transactions

The Company did not engage in any related party transactions during the year ended December 31, 2017, other than key management compensation as disclosed.

22. Subsequent Events

In January 2018, Credit Facility A was renewed at $17.9 million and Credit Facility C remains at $0.1 million.

Corporate Information

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Earl Hickok

Hans Jacob Holden

Dennis Sykora

Bjorn Inge Tonnessen

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